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ENERGY TAX PROVISIONS

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MISCELLANEOUS PROVISIONS OF H.R. 8444; ENERGY INCENTIVES AND OIL IMPORTS

PREPARED FOR THE

COMMITTEE ON FINANCE
UNITED STATES SENATE

BY THE STAFF OF THE

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I. INTRODUCTION

This pamphlet is the sixth in a series prepared for use by the Committee on Finance during its consideration of the tax provisions of the House-passed energy bill (Title II of H.R. 8444). This pamphlet describes in detail the miscellaneous provisions of the House bill. It also includes descriptions of conventional and innovative energy sources, incentives for increasing energy supply and production, the treatment of imported petroleum products, and other energy-related issues. The descriptions include sections on economic and other background information, present law, the House bill, the Administration position, and areas for Committee consideration, as well as the relevant energy tax proposals considered by the Senate during the 94th Congress and nontax, provisions under consideration in the 95th Congress.

In the 94th Congress, the major bill considered in connection with energy tax proposals was H.R. 6860. This bill was reported by the Ways and Means Committee and was amended on the House floor. Markup sessions on H.R. 6860 were held by the Finance Committee in July 1975, and tentative decisions were made in many areas, but the bill was not reported at that time. Many of the provisions approved by the Finance Committee were added to the Tax Reform bill (H.R. 10612), as Title XX, but all of the energy provisions were deleted in conference. In August 1976, the Finance Committee reported the provisions of Title XX (as passed by the Senate) as an amended version of H.R. 6860. This bill was never taken up on the Senate floor, and the provisions expired with the adjournment of the 94th Congress.

Unless otherwise indicated, references to the Finance Committee bill refer to Title XX of the Tax Reform bill (as passed by the Senate) and to the Finance Committee's reported version of H.R. 6860. Amendments on the Senate floor (to Title XX of the tax reform bill) are specifically noted.

I. MISCELLANEOUS PROVISIONS OF THE HOUSE BILL

A. Intangible Drilling Costs of Oil and Gas Wells

1. Background

Between 1960 and 1973, the combination of a gradual increase in the difficulty of finding new oil and a decline in the price of oil relative to other goods and services led to a sharp decline in drilling activity. The number of wells drilled declined from 47,000 in 1960 to 28,000 in 1973, and the footage drilled fell from 191 million feet to 139 million feet.[1]

Since 1973, however, there has been a significant increase in drilling activity because of the sharp increase in oil prices. Footage drilled increased by 33 percent between 1973 and 1976, and the number of wells drilled rose by 50 percent.

2. Present law

Under present law, the operator of an oil or gas well may elect to deduct intangible drilling and development costs as an expense rather than capitalize the costs and recover them through depletion and depreciation deductions. Generally, intangible drilling and development costs are defined as those expenditures made by the owner of the operating interest for wages, fuel, repairs, hauling, supplies, etc., incurred in preparing a drill site, drilling and cleaning a well, and constructing assets which are necessary in drilling the well and preparing it for production (such as derricks, pipelines and tanks).

Under the Tax Reform Act of 1976, the deduction for intangible drilling costs in excess of the deduction which would have been allowed with respect to those costs for that year through either 10-year amortization or cost depletion is treated as a tax preference item for purposes of the minimum tax for individuals.

In the Tax Reduction and Simplification Act of 1977, the Congress provided that for taxable years beginning only in 1977 intangible drilling and development costs (over the amount which would have been allowable under either 10-year amortization or cost depletion) in excess of oil and gas production income would constitute a tax preference item. However, this rule would not apply for future years unless there is further Congressional action.

3. House bill

The House-passed bill would extend for all future years the minimum tax provision on intangible drilling costs of individuals currently applicable for 1977. As a result, intangible drilling cost deductions for oil or gas wells would be included in the minimum tax base of individuals only to the extent that intangible drilling and development costs, over the amount of those costs amortizable on the basis of a 10-

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[1] *U.S. Petroleum Statistics 1977* (Preliminary), published by the Independent Petroleum Association of America.

year life or under cost depletion, exceed the taxpayer's income from oil and gas properties. Income from oil and gas properties is to be determined first with reference to the rules for determining gross income from oil and gas properties for purposes of percentage depletion (sec. 613(a) of the Code, without regard to the limitations under sec. 613A). Net income from oil and gas properties is gross income from oil and gas properties reduced by the amount of deductions properly attributable to that gross income (and deductions attributable to oil and gas properties with no gross income), except that no reduction is to be made for those intangible drilling costs subject to the minimum tax (i.e., those incurred on successful wells).

4. Administration position on the House bill

The Administration supports this provision of the House bill.

5. Other Congressional consideration

a. Action in the 94th Congress

The Finance Committee made no decisions with respect to additional incentives for oil and gas exploration or production.

b. Other committee action in the 95th Congress

(To be supplied.)

6. Areas for committee consideration

The House bill extends for all future years the minimum tax provision on intangible drilling costs of individuals. That provision reduces the minimum tax preference to the amount by which intangible costs (in excess of the amount amortizable over 10 years or through cost depletion) exceed oil and gas production income of the taxpayer. The House bill is thus the same as the provision adopted by the Finance Committee in the 1976 Tax Reform Act and adopted this year as a Senate floor amendment to the 1977 Tax Reduction and Simplification Act. On both occasions, this reduction in the preference was adopted in order to limit the tax benefits which can be obtained by sheltering outside income with intangible drilling deductions without providing a disincentive to taxpayers who are in the business of exploring for oil and gas.

B. Geothermal Deposits

1. Background

Geothermal energy is the natural heat contained in the crust of the earth. Although present everywhere throughout the crust, only in a few areas is it sufficiently concentrated and near to the surface to make its recovery presently economically viable.

Types of geothermal energy

The various classes of geothermal resources in the order of their relative ease of recovery and economic utilization are:

Vapor-dominated.—Vapor-dominated geothermal resources contain saturated or superheated steam. To date, only six major vapor-dominated reservoirs have been located in the world. In the United States, the only commercially producing geothermal field is located at the Geysers, California, a dry steam field about 80 miles north of San Francisco. It has a production capacity of over 500 megawatts (MW). The complex was developed and is operated (by the Pacific Gas and Electric Company) with nongovernmental funds. The steam price is calculated from a base price which is adjusted by the cost of other fuels used by the utility in its other thermal plants. Electricity produced at The Geysers costs consumers 18 mills per kilowatt (kW), while nuclear power costs 24 mills, coal-generated power 30 mills, oil-generated power 36 mills

Liquid-dominated.—Liquid-dominated geothermal resources have naturally occurring liquid water, or a naturally occurring two-phase mixture of liquid water and steam, at an elevated temperature and pressure. In some instances, these dissolved minerals have been found to render conventional pipelines useless due to the tendency of the minerals to solidify quickly inside the pipeline. The water contains solids dissolved from the rocks. Most hydrothermal sites throughout the world are of the liquid-dominated type; they are perhaps 20 times more numerous than vapor-dominated sites.

The high-temperature hydrothermal convection systems (that is, systems of liquid above 150° C., which circulate because of variations in their density and the action of gravity) with a potential for generating electricity are predominantly in the Western United States, including Alaska and Hawaii. The identified systems of this type are estimated by the U.S. Geological Survey[1] to have energy reserves of 11,550 megawatts of electricity, per year for 30 years, producible at

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[1] The U.S. Geological Survey, a bureau under the Department of the Interior, has among its responsibilities the topographic mapping of the United States; the geological study of the nation, including locating and analyzing minerals throughout the fifty States and the Outer Continental Shelf; the monitoring of U.S. surface and ground water resources; and the conservation of the nation's natural resources by overseeing safety and environmental protection in and by measuring the production of minerals, including oil and gas, on public and Indian lands and on the Outer Continental Shelf.

1975 prices and technology, and about an equal amount of energy resources recoverable at costs between one and two times the 1975 price of competitive energy. Undiscovered high-temperature hydrothermal resources were predicted to be about five times greater than identified resources.

The intermediate-temperature hydrothermal convection systems (90° C.) are potential providers of direct thermal energy for home and industrial heating, thereby releasing oil and gas for other uses. If this heat were to be supplied by electrical energy, the Survey estimates that the equivalent of about 90,750 megawatts would be available annually for 30 years.

Geopressured.—Geopressured geothermal resources are extensive, deep (1 to 4 miles) zones of pressurized water with widely varying salinity in which the pressure exceeds the corresponding pressure of the water at that depth. This overpressure is caused by the weight of the geological formation (overlying the trapped fluid), which is greater than the weight of an equal volume of fluids. Geopressured systems contain water at temperatures measured at approximately 60° to 180° C. and pressures from about 3,000 to 14,000 psi together with potentially exploitable dissolved methane. Areas for potential development are located in the Gulf Coast states.

The geopressured fluids of the Gulf Coast have a very large energy potential. The energy deliverable at the wellhead in the onshore part of the region that has been assessed by the U.S. Geological Survey was estimated to range from 30,000 to 115,000 megawatts per year for 30 years. This range excludes the energy equivalent of the recoverable methane, which is thought to be at least equal in value. Other geopressured ections of the Gulf Coast and other regions of the country probably have at least three times more potential energy than the evaluated part, but the recoverable fraction may be considerably less because of a lower average porosity and permeability which naturally makes it much harder for the methane to be extracted. Much of the geopressured resource was considered by the Survey, to be recoverable at from one to two times 1975 prices.

The recovery of geopressurized gas (methane) located under the ocean beds, entails significant problems which require technological solutions before this resource can be exploited commercially. Locating deposits of geopressured water, containing dissolved methane is still an erratic endeavor. Most deposits have been found by accident. Producing this gas would require handling vast quantities of water. It is estimated that 13⅓ barrels of water must be processed to obtain 1,000 cubic feet of gas. To produce enough gas to fill the U.S. current annual demand of 20 trillion cubic feet would require lifting, treating and disposing of 266 trillion barrels of water.

The intense heat and corrosive quality of the water containing geopressurized gas pose additional problems. The heat could significantly and adversely alter the ocean environment, if the hot water is discharged without cooling or dilution. The dissolved minerals in many of the deposits make the water so corrosive that it quickly corrodes all known materials. Thus, new materials must be developed for the equipment used in such operations. Moreover, drilling for geopressurized gas will require wells of far greater circumference than existing wells, and therefore will require bores far larger than any present equipment. Wells would have to reach approximately 30 miles deeper than any wells yet drilled.

Such drilling could involve major dislocations of the ocean bottom and of vast quantities of water, and would probably cause surface subsidence (sinking) in coastal areas. Some method of disposing of the water used in this process and of balancing the ecological disturbances must be devised. Although geopressurized gas is potentially a vast resource estimated to be sufficient to supplement current levels of natural gas use for 100 to 250 years, it is still in the research stage and is unlikely to contribute significantly to actual energy reserves in the near future.

Hot dry rock.—Hot dry rock geological formations are those having an abnormally high heat content, but not containing sufficient water or sufficient rock permeability to permit withdrawal of hot water as a heat transport medium.

Magma.—Magma formations comprise molten rocks at approximately 500° to 1500° C. Very deep drilling, 20 miles or more, will be required to reach magma in most regions of the United States. Magma is reachable at drillable depths in some active volcanic areas, such as in Hawaii.

Potential of geothermal energy

Small geothermal plants can be constructed economically in the United States at present. The small size of the geothermal plant gives it a distinct advantage in areas that cannot finance the large investment required for the 1,000 megawatt installation usually needed for efficient plants using other fuels. However, the geothermal electrical plants must be located near the energy source as must any other facility that directly uses geothermal heat. Any geothermal resources used for new generating plants would largely replace plants whose fuel would otherwise be Western coal.

Geothermal energy has been used for the generation of electricity in Italy since 1904, and has helped satisfy the space heating requirements in Reykjavik, Iceland. Other countries actively using or building geothermal plants for electric or nonelectric applications include Japan, New Zealand, Mexico, the Philippines, France, and the USSR. Other relatively small-scale applications of geothermal energy for space heating are widespread throughout the western United States. For example, at Klamath Falls, Oregon, the Oregon Institute of Technology and many private homes are heated by water from geothermal wells. Plans are underway to use geothermal energy for heating one of the capitol buildings in Boise, Idaho.

The U.S. Geological Survey, to implement the Geothermal Steam Act of 1970, has designated about 1.8 million acres on the western United States as being "known geothermal resources areas" and an additional 96 million acres as having prospective value for geothermal resources.

2. *Present law*

Under current law, it is unsettled whether the production of geothermal steam and associated geothermal resources qualifies for either a percentage depletion deduction or the intangible drilling cost deduction. However, in *Reich* v. *Commissioner*, 454 F. 2d 1157 (9th

Cir. 1972), aff'g, 52 T.C. 700 (1969), the Ninth Circuit held that the production of geothermal steam entitled the taxpayers to both deductions to the extent that such deductions were available for gas wells.[2] Nevertheless, the Internal Revenue Service apparently is not following the *Reich* decision in cases arising outside of the Ninth Circuit.

Except in the case of certain small producers, the Tax Reduction Act of 1975 generally eliminated the depletion allowance for oil and gas. That Act, however, did not affect the issue of whether geothermal resources qualify for percentage depletion. As a result, the 22-percent depletion deduction allowable to gas wells immediately prior to the 1975 Tax Reduction Act still is available for geothermal energy if courts should decide, as did the *Reich* court, that certain geothermal wells are gas wells and that the other requirements for depletion are met.

Even if the decision of the *Reich* court is not followed, under present law expenditures incurred in connection with the exploratory phase of geothermal energy which result in dry holes are deductible at the time when the well (or leasehold) is abandoned. Moreover, to the extent that these costs result in new processes or technology, it is possible under present law that these costs would be considered to be research and experimental expenditures subject to the election to be deducted currently or to be amortized over a 60-month period. For example, in Revenue Ruling 74–67, 1974–1 C.B. 63, the Internal Revenue Service held that certain costs of developing a method for the hydraulic mining of hard minerals, including a portion of the cost of drilling wells, were deductible as research and experimental expenditures. However, under current law the costs of determining the existence, location, extent, or quality of any oil, gas, or other mineral deposit are not deductible as research and experimental expenditures, and must be capitalized.

To the extent that geothermal wells are determined to be gas wells, as they were by the *Reich* court, the minimum tax, the recapture provisions and the at risk rules which the Tax Reform Act of 1976 applied to oil and gas wells would apply to geothermal wells. Under the Tax Reform Act of 1976, the deduction for intangible drilling costs on oil and gas wells is treated as a tax preference item for purposes of the minimum tax to the extent that it exceeds the amortization which would have been allowed on the basis of a 10-year life or cost depletion. The Tax Reduction and Simplification Act of 1977 provided, however, that for taxable years beginning only in 1977 the excess of the intangible drilling and development costs, over the amount amortizable, which further exceeded oil and gas production income, would constitute a tax preference item.

The Tax Reform Act of 1976 also provided for the recapture of certain intangible drilling and development costs upon the disposition of oil and gas properties. The amount subject to recapture is the amount deducted for intangible drilling and development costs reduced by the amount which would have been deductible had those intangible costs been capitalized and deducted through cost depletion. The amount recaptured is to be treated as ordinary income; it cannot exceed the gain realized or the difference between the fair market value of the property transferred over the basis in the property. The recapture rule generally applies regardless of any other provision of the Code which otherwise would provide for nonrecognition and applies on a property-by-property basis.

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[2] In the *Reich* case, the Tax Court had held that the product of the taxpayers' geothermal steam wells was a gas, and that the taxpayers as a result were entitled to expense currently their intangible drilling costs (sec. 263(c) of the Code). The court held further that the taxpayers were entitled to the then 27½ percent depletion deduction allowance for their product because (1) their product was steam, not inexhaustible earth heat, (2) the particular geothermal wells in question were exhaustible, (3) steam is a gas, and (4) the exclusion from the right to depletion of "water" in section 613(b)(7) of the Code does not exclude steam from the depletion allowance.

In addition, the Tax Reform Act of 1976 provided that the amount of any loss (otherwise allowable for the year) which may be deducted in connection with exploring for, or exploiting, oil and gas resources cannot exceed the aggregate amount with respect to which the taxpayer is at risk with respect to the property at the close of the taxable year (i.e., generally the amount of an otherwise allowable loss for the year cannot exceed the taxpayer's basis reduced by any nonrecourse borrowing to which the property is subject). The at risk limitation applies to all taxpayers except corporations which are not subchapter S corporations or personal holding companies.

3. *House bill*

The House-passed bill provides taxpayers with the option to deduct currently, rather than to capitalize, intangible drilling and development costs related to the exploration for, and the development of, geothermal deposits. Geothermal deposits are defined by the bill to mean geothermal reservoirs consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure). The election to capitalize or to deduct intangible drilling costs must be made prior to the expiration of the time for filing claims for credit or refund of any overpayment of tax imposed with regard to the taxpayer's first taxable year to which the bill is effective and for which intangible drilling costs are paid or incurred. Prior to the expiration of this period, but not thereafter, the election may be changed or revoked.

The bill also provides that the excess of the intangible drilling and development costs over the amount of those costs which would have been amortizable on the basis of a 10-year life and which further exceed the taxpayer's income from the production of geothermal resources constitutes a tax preference item for purposes of the minimum tax on individuals. Since some geothermal resources may be renewable to some extent, the bill provides that the amortizable amount which reduces the amount of the preference is to be determined on a 10-year life basis in all cases, rather than allowing the option of computing cost depletion on that resource. To ascertain the amount of the intangible drilling and development costs over the amount amortizable, which is subject to the minimum tax, the taxpayer's income from oil and gas properties is to be determined separately from the calculation of income from geothermal properties.

The bill also provides that gain on the disposition of geothermal properties will be subject to recapture (i.e., treated as ordinary income rather than capital gain) to the extent that the amount of the intangible drilling cost deductions exceed the amount which would have been allowable had the costs been capitalized and deducted through cost depletion.

Furthermore, the bill provides that the amount of any loss (otherwise allowable for the year) which may be deducted in connection with exploring for, or exploiting, geothermal deposits cannot exceed the aggregate amount with respect to which the taxpayer is at risk at the close of the taxable year, as determined under existing law (sec. 465). The at risk limitation applies to all taxpayers other than corporations which are not subchapter S corporations or personal holding companies.

In addition, the bill provides a 10-percent allowance for percentage depletion for all geothermal resources regardless of whether or not the geothermal resource would qualify for depletion under present law and regardless of whether or not the resource in fact is renewable. However, the amount of allowable depletion with respect to any property in any year may not exceed the taxpayer's adjusted cost basis in that property.[3]

4. *Administration position on the House bill*

The Administration supports the provision of the House bill relating to intangible drillng costs and has no objecton to the provision relating to the depletion allowance.

5. *Other Congressional consideration*

a. Action in the 94th Congress

In Title XX of its version of H.R. 10612 (the Tax Reform Act of 1976), the Finance Committee provided for the current expensing of intangible drilling costs for wells drilled for geothermal steam and associated geothermal resources. The bill also would have provided a deduction (in the nature of, but in lieu of, a depletion deduction) for 22 percent of the gross income from the property for the production of geothermal steam and associated geothermal resources, but not to exceed 50 percent of taxable income from this property. This deduction would have been considered a tax preference for purposes of the minimum tax.

In addition, the Committee's bill would have extended the investment tax credit to qualified geothermal energy equipment installed for use in a trade or business or as part of a facility held for the production of income. The amount of the credit would have been 20 percent, and would have been applicable whether or not the equipment otherwise would have qualified for the credit.

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[3] For example, assume that the taxpayer's basis in the property is $100,000, and that gross income from the property for year one is $600,000. The allowable percentage depletion deduction for year one (assuming that the 50-percent net income from the property and the 65-percent taxable income limitations do not apply) will be $60,000 ($600,000×10 percent), thereby reducing the basis of the property to $40,000. If the gross income from the property for year two is $600,000, the allowable percentage depletion deduction for year two will be $60,000. However, since the adjusted basis of the property at the beginning of year two is $40,000 (assuming both that no deductions which reduce basis, or downward adjustments to basis, were made in year one), only $40,000 of the otherwise permissible percentage depletion deduction of $60,000 is allowable. The excess $20,000 may not be deducted in year two or in any subsequent year, and no depletion deduction will be allowable for future years, unless the adjusted basis of the property is increased.

These provisions were passed by the full Senate but deleted in Conference.

The Finance Committee reported similar provisions in its version of H.R. 6860, a bill which was not acted on by the full Senate.

b. Other committee action in the 95th Congress

Title I of the House bill allows the Secretary of Energy to deregulate the prices for any non-conventional gas, such as geopressurized gas (methane).

6. Areas for committee consideration

1. *Geological and geophysical expenses.*—To provide an additional incentive for the exploration for, and the development of, geothermal resources, the Committee may want to consider changing the present law requirement that geological and geophysical expenses incurred in the exploration for geothermal resources be capitalized. The Committee could provide taxpayers with an option to deduct these costs currently. This change could provide an additional incentive for taxpayers to undertake exploration for recoverable resources, such as geothermal steam and geopressurized gas, which are not located easily.

2. *Percentage depletion.*—Another action which the Committee may want to consider to stimulate the development of geothermal resources is increasing the depletion allowance for geothermal deposits from the 10-percent rate provided in the House-passed bill to a higher percent. At present production levels, a 22-percent depletion deduction would cost less than $5 million annually. The Ninth Circuit has held that geothermal steam is a gas subject to the depletion allowance.[4] Section 613A(b)(1)(C) of the Code provides that any geothermal deposit which is determined to be a gas well is allowed a 22-percent depletion rate. Since the only operating geothermal plants, and the greatest amount of projected geothermal deposits, are located within the jurisdiction of the Ninth Circuit, present law effectively permits a 22-percent depletion allowance in the case of geothermal steam.

The provision contained in the House-passed bill, which provides for a 10-percent depletion allowance for all geothermal resources regardless of whether they would qualify for depletion under present law or are renewable in fact, effectively reduces the depletion rate allowed in the case of geothermal steam by 12 percentage points. However, the House-passed bill would allow depletion with respect to all geothermal resources, including renewable geothermal heat, regardless of whether it is depletable, and without the inevitable necessity of litigation where the deposit is located outside of the Ninth Circuit's jurisdiction. But since most projected geothermal resources are located in the Ninth Circuit, the House bill may be providing an illusory incentive.

To reduce the presently allowable depletion rate from 22 to 10 percent probably would be a disincentive to the development of geothermal resources. Therefore, the more reasoned option would be to clarify present law as to the allowance of a 22-percent rate in the case of geothermal steam, *i.e.*, treat it as a gas well within the meaning of § 613A(b)(1)(C), while noting that geothermal heat (a renewable resource currently not recoverable in an economically viable manner) does not fall within the 22-percent depletion rate classification. The Committee, however, could consider retaining the 10-percent rate for geothermal resources other than geothermal steam, i.e. those which have not been determined to be a depletable gas. Such an action would be consistent with the House's intention to provide a 10-percent rate without regard to whether the resource would qualify for depletion, or was renewable in fact.

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[4] *See Reich v. Comm'r*, 454 F.2d 1157 (9th Cir. 1972), *aff'g*, 52 T.C. 700 (1969).

3. *Residential systems.*—The Committee also may want to allow a tax credit, similar to the credits contained in the House-passed bill for the installation of insulation and solar equipment, for the installation of a residential geothermal steam distribution system. Such a credit is contained in the House-passed bill for business installaton of geothermal steam distribution systems.

4. *Advanced technology equipment.*—In addition, the Committee may want to consider expanding the definition of advanced technology equipment contained in the House-passed bill to include equipment specially designed and developed to recover geopressurized gas. By expanding this definition the Committee could provide taxpayers with an incentive to develop the specialized equipment necessary both to recover geopressurized gas, and to withstand the corrosiveness of geopressurized brine. The expanded definition also could include the equipment and facilities necessary to purify brine for safe disposition, or to reintroduce it into the ground.

5. *Rapid amortization.*—In the case of equipment needed to drill for and recover geopressurized gas, a rapid amortization period could be allowed. This would permit a quicker recovery of the capital outlays required, and therefore should provide an incentive for taxpayers to incur the additional costs involved in developing geopressurized gas resources. The rapid amortization period could apply to all equipment used in the drilling, recovery, purifying and storage phases, in addition to equipment and facilities needed to dispose of the brine which may accompany the recovery of the gas.

Alternatively, the Committee could provide an option for taxpayers to expense the cost of brine disposal or recycling equipment.

6. *Research and development.*—To expedite the development of geothermal resources and geopressurized gas, the Committee may want to consider allocating some of the funds generated by the various taxes contained in the House-passed bill for research and development grants, loans, or loan guarantees for such resources.

C. Rerefined Lubricating Oil

1. *Background*

Annually there are hundreds of millions of gallons of previously used lubricating oil available for recycling. Yet, according to recent studies, almost half of this amount is disposed of in an indiscriminate and environmentally unsafe manner. Since 1965 the number of used oil rerefiners in the U.S. has fallen from approximately 150 to 30, and the number of gallons of reprocessed oil has fallen from 300 million to less than 100 million.

Prior to the enactment of the Excise Tax Reduction Act in 1965, there had been a 6-cent-per-gallon tax levied on the manufacture of all lubricating oil. This tax was paid by the first user of the oil. Because rerefiners were not required to pay this tax, they had a 6-cent-per-gallon competitive edge over oil refiners.

In 1965, the Internal Revenue Service ruled that since these excise tax revenues were to go into the Highway Trust Fund, off-highway users would be refunded the full 6-cent-per-gallon payment on virgin lubricating oils. In addition, the Service refused to allow tax rebates on any virgin oils which were to be blended with rerefined oil to meet user viscosity requirements. As a result, the rerefiner lost a 6-cent-per-gallon differential, and was subject to an additional 3-cent-per-gallon tax if he used a 50–50 blend of recycled and virgin oil.

Moreover, in 1965, the Federal Trade Commission ruled that all rerefined oils produced for sale to the public had to be labeled "previously used," implying an inferior product. This ruling apparently precipitated a reduction in consumer sales.

2. *Present law*

Present law imposes a manufacturers excise tax of 6-cents-per-gallon on lubricating oil (other than cutting oils) sold in the United States by the manufacturer or producer (sec. 4091). Also, a manufacturer of lubricating oil is liable for the tax if he uses the oil himself rather than selling it (unless the oil is used in manufacturing a product which is subject to a manufacturers excise tax). The net revenues from the tax (after refunds or credits for nonhighway use) go into the Highway Trust Fund (through September 30, 1979).

Cleaning, renovating, or refining used oil is not considered manufacturing, so the sale of recycled or rerefined oil by a refiner is not subject to the excise tax. However, where new lubricating oil is mixed with waste or rerefined oil, this does constitute manufacturing, and the excise tax is imposed on the portion of the mixture which consists of new lubricating oil.

Although present law taxes most sales of lubricating oil, present law also allows a tax refund or credit where lubricating oil is used for any purpose other than lubricating a highway motor vehicle. No refund is available where the oil, including rerefined oil, was exempt from tax in the first place. However, present law also denies the exemption where part of the oil was exempt from tax. As a result, when new oil and rerefined oil are blended, a tax is imposed on the new oil portion of the blend, but no refund or tax credit is available.

In nontax areas, Congress has recently acted to encourage the use of recycled oil. Under section 383 of the Energy Policy and Concervation Act (Public Law 94–163), various Federal agencies are instructed to encourage the recycling of used oil, and to promote the use of the oil so processed or rerefined. The purpose of this mandate is to reduce the consumption of new oil by using recycled oil where appropriate, and to reduce environmental hazards and wasteful practices associated with the disposition of used oil. Recycled oil is to be tested to determine the uses for which it is substantially equivalent in performance to new oil; existing Federal rules pertaining to the labeling of recycled oil are to be changed so that recycled oil which is substantially equivalent to new oil will not be labeled to connote that it is less than equivalent to new oil for a particular purpose. In addition, the Act instructs Federal officials to revise procurement practices to encourage the procurement of recycled oil for military and nonmilitary uses wherever such recycled oil is available at prices competitive with new oil produced for the same use.

3. *House bill*

The House-passed bill would exempt the sale of lubricating oil from the 6-cents-per-gallon manufacturers excise tax where the lubricating oil is sold for use in mixing with previously used or waste lubricating oil which has been cleaned, renovated, or rerefined. For the exemption to apply, the blend of old and new oil must consist of 25 percent or more of waste or rerefined oil. All of the new oil in a mixture is to be exempt from the excise tax if the blend contains 55 percent or less new oil. If the mixture contains more than 55 percent new oil, the excise tax exemption applies only with regard to the portion of the new oil that does not exceed 55 percent of the mixture.

4. *Administration position on the House bill*

The Administration supports this provision of the House bill.

5. *Other congressional consideration*

Action in the 94th Congress

In Title XX of the Tax Reform bill (H.R. 10612), the Finance Committee provided for an exemption identical to that contained in the House-passed bill. This provision was deleted in Conference.

The Finance Committee reported a similar provision in H.R. 6860, a bill which was not acted on by the Senate.

6. *Areas for Committee consideration*

The Committee may want to adopt the House provision which is identical to prior action taken by the Committee and passed by the Senate.

D. Annual Report on Energy and Revenue Effects of Tax Provisions

1. *Background*

Historically, there has been an ongoing effort by a variety of Federal agencies to collect statistical data on the consumption and production of energy.

The new Department of Energy will consolidate the various programs and will have an administrator responsible for collecting and analyzing energy data.

2. *Present law*

Present law does not require a periodic report by an agency of the Executive branch on the revenue gain or loss or the energy savings from a particular bill. Annual reports are required, however, of Cabinet officers and the heads of independent agencies, in which the complete range of the agencies, activities for the year are described. In addition, annual reports to the Congress are required regarding the operation of the various trust funds—such as the Airport and Airway Trust Fund, the Highway Trust Fund, and the Social Security Trust Fund.

3. *House bill*

The House bill requires the President to submit an annual report to the Congress every August, beginning in 1978. The report is to estimate the revenue increases or decreases resulting from each of the tax provisions of title II of H.R. 8444, and to evaulate the extent to which each of the provisions has resulted in increased energy conservation and production.

The bill also requires that the President provide any other information which is determined to be relevant for an evaluation of the provisions of the bill. The Ways and Means Committee Report indicates that it is expected that the report will include the petroleum (or natural gas) savings resulting from each provision and the extent to which shifts from petroleum and natural gas to other materials has occurred as a result of each provision.

4. *Administration position on the House bill*

The Administration has no objection to this provision of the House bill.

5. *Other congressional consideration*

Action in the 94th Congress

The Finance Committee bill did not provide for any study of the impact of energy legislation on energy supply and production. It did, however, provide in H.R. 6860, that the Treasury Department study the feasibility and revenue effects of providing tax incentives for recycling.

6. *Areas for committee consideration*

1. The Committee may want to broaden the study to include both the tax and nontax provisions of the legislation.

2. The Committee also may want to require the Secretary of Energy to collect data on energy consumption and related information in a consistent manner according to economic sector (agriculture, industrial, commercial, residential, government, etc.) to assist future analysis of the impact of energy on the economy.

II. ENERGY DEVELOPMENT AND PRODUCTION INCENTIVES

The following section of this pamphlet describes present and possible future sources of energy. The information provided in this section is organized generally according to the various resources available to the United States for energy development and production. The topics discussed are oil and gas wells, oil shale, Devonian shale, coal mining, coal slurry pipelines, coal gasification and liquefaction, bioconversion, ocean energy and chemical energy. (For a discussion of residential solar and wind energy development tax credits, see staff pamphlet No. 2; for a discussion of various alternative energy property credits, see staff pamphlet No. 5.)

Some of these energy resources could make significant contributions to U.S. energy supplies in the very near future. In a few cases, the private sector already has developed the technology and obtained the economic means for independently producing energy from these resources on a commercial scale. In other cases, government assistance may be required to expedite, or perhaps even to insure, such production.

However, most of these resources can be expected to increase U.S. energy supplies only in the long-range future. In the case of resources which might add significantly to energy supplies, legislative action to provide Federal help, either through economic assisance to the private sector or through new or expanded governmental research and development programs, could prove vital.

In considering any legislative action with regard to these energy resources, the Committee probably will want to distinguish the areas which have the most immediate potential for increasing energy supplies from other areas which will require extensive, long-term research before their production can be expected to approach commercial scale. Development of the former category might be expedited by means of such measures as price guarantees, new tax benefits, Federal loans, or loan guarantees provided, perhaps, through a special energy trust fund or energy finance corporation. (See part III of staff pamphlet No. 4.) Development of the long-term sources of energy might be served better through government-conducted or government-assisted research and development, perhaps up through the construction and operation of pilot projects.

During its deliberations about these various resources, the Committee will have to consider the revenue costs of its decisions. Budgetary constraints will require careful evaluation of all proposals because the provision of incentives for expenditures in some areas will limit the amount of funds available for others. The Committee also will want to consider whether or how its actions may affect consumers—in terms of energy price rises, income tax increases and other related economic, as well as environmental and ecological effects. Any decisions made by the Committee in the following areas will have to be considered together with its decisions with regard to the other provisions of the House-passed bill in order to measure the overall impact of the Committee's action, not only on energy, but also on the entire economy.

A. Oil and Gas Wells

1. Background

Oil and gas production and drilling activity

U.S. oil and gas production grew rapidly through 1970, but it has declined since then. Statistics on oil and gas production are shown in table 1. Petroleum production (including natural gas liquids produced at processing plants) peaked in 1970 at 11.30 million barrels per day (mbd) and has declined to 9.50 mbd in early 1977, a decline of 16 percent, or about 2 percent per year. Marketed production of natural gas peaked in 1973 at 22.65 trillion cubic feet (tcf) and declined to 19.90 tcf in 1976, a decline of 12 percent, or 4 percent per year. United States' imports of foreign natural gas are minimal and therefore are not reflected in table 1.

Alaskan oil will boost production in the second half of 1977 and in subsequent years by 1 to 2 mbd, but if production in the lower-48 States continues to decline, the Alaskan oil still will not be enough to restore the 1970 rate of petroleum production, much less permit any growth in U.S. production above that level to offset the increases in oil consumption which are expected to occur.

There are several reasons for the declining oil and gas production in the lower-48 States. Drilling for oil and gas declined significantly between the mid-1950's and 1971. This is shown in table 2, which presents several indicators of drilling activity. The number of well completions, number of exploratory wells drilled, the total footage drilled and the number of rotary rigs in operation all declined steadily from 1957 to 1971. Drilling activity was cut approximately in half. To a large extent, this decline in drilling was a response to the price of oil and gas. Between 1957 and 1970, the wellhead price of oil declined by 27 percent relative to consumer prices generally, and the price of natural gas rose by only 7 percent, relative to consumer prices, from the very low natural gas prices prevailing in the 1950's.

TABLE 1.—*U.S. production of oil and gas, U. S. demand for petroleum, U.S. oil imports, and natural gas production*

Year	Production of petroleum[1] (million of barrels/day)	U.S. demand for petroleum (million of barrels/day)	U.S. oil imports (million of barrels/day)	Marketed production of natural gas (trillion cubic feet/year)
1955	7.58	8.49	1.25	9.41
1956	7.95	8.82	1.44	10.08
1957	7.98	8.86	1.57	10.68
1958	7.52	9.15	1.70	11.03
1959	7.93	9.49	1.78	12.05
1960	7.97	9.81	1.82	12.77
1961	8.17	9.99	1.92	13.25
1962	8.35	10.41	2.08	13.88
1963	8.64	10.75	2.12	14.75
1964	8.77	11.03	2.26	15.46
1965	9.01	11.52	2.47	16.04
1966	9.58	12.10	2.57	17.21
1967	10.22	12.57	2.54	18.17
1968	10.60	13.40	2.84	19.32
1969	10.83	14.15	3.17	20.70
1970	11.30	14.71	3.42	21.92
1971	11.15	15.23	3.93	22.49
1972	11.18	16.37	4.74	22.53
1973	10.95	17.31	6.26	22.65
1974	10.46	16.65	6.11	21.60
1975	10.01	16.32	6.06	20.11
1976	9.72	17.44	7.29	19.90
1977[2]	9.50			

[1] Includes natural gas liquids.

[2] January–February average.

Sources: Independent Petroleum Association of America (1955–71) and *Monthly Energy Review* (1972–77).

TABLE 2.—*Oil and gas drilling 1957–77*

Year	Well completions (thousands)	Exploratory wells (thousands)	Total feet drilled (millions)	Rotary rigs in operation
1957	53.6	14.7	233.1	2,429
1958	48.4	13.2	198.2	1,923
1959	50.1	13.2	209.2	2,074
1960	44.0	11.7	190.7	1,746
1961	43.9	11.0	192.1	1,763
1962	43.8	10.8	198.6	1,637
1963	41.4	10.7	184.4	1,501
1964	43.0	10.7	189.9	1,502
1965	39.5	9.5	181.5	1,388
1966	36.4	10.3	166.0	1,270
1967	32.2	8.9	144.7	1,134
1968	30.6	8.8	149.3	1.170
1969	32.2	9.7	160.9	1,195
1970	28.1	7.7	142.4	1,028
1971	25.9	6.9	128.3	975
1972	27.3	7.5	138.4	1,107
1973	26.6	7.5	138.9	1,194
1974	31.7	8.6	153.8	1,475
1975	37.2	9.2	178.5	1,660
1976	39.8	9.2	185.2	1,656
1977 [1]	40.8	NA	NA	1,915

[1] Average for 1st part of year.

Sources: Independent Petroleum Association of America, *Monthly Energy Review.*

Oil and gas drilling activity has picked up considerably since 1971, although it has not attained the levels of the late 1950's. Total footage drilled rose from 128.3 million feet in 1971 to 185.2 million feet in 1976 (compared to 233.1 million feet in 1957). So far in 1977, drilling activity has increased further; the number of rotary rigs in operation, which rose from 1975 in 1971 to 1,656 in 1976, averaged 1,915 in the first 6 months of 1977. (There were an average of 2,429 rotary rigs in operation in 1957.) The increase in drilling appears to be concentrated somewhat more on development drilling than exploratory drilling. According to the definitions used by the Independent Petroleum Association of America, the number of wildcat wells has grown by 33 percent since 1971, while the total number of wells completed has risen by 54 percent.

Between 1957 and 1971, the decline in drilling activity was offset to some extent by an increase in the amount of oil discovered per well drilled. This statistic fluctuates greatly from year to year, so trends are best analyzed through averages of several years' data. In the period 1956–59, an average of 107,000 barrels of crude oil was discovered for every new oil well, compared to an average of 187,000 barrels per oil well in the period 1967–70 (excluding Alaska). However, since 1971 the amount of oil discovered per well has declined sharply, and in 1975 it equaled only 80,000 barrels. There also has been a sharp decline in the amount of gas discovered per new well, which averaged 4.5 billion cubic feet in 1956–59 and only 1.2 billion cubic feet in 1973–75. It is not clear to what extent these recent declines in drilling success result from the nature of the drilling being done, bad luck, or simply to the fact that there is progressively less undiscovered oil and gas remaining in the ground.

Oil and gas prices

One factor determining oil and gas production is the wellhead price at which these products are sold. At higher prices, drillers will be willing to assume greater risks by drilling into less promising areas or in areas where extraction costs are higher. Also, at higher prices, producers will be more willing to invest in enhanced recovery techniques and will find it profitable to maintain production from higher cost wells, such as stripper wells. Unfortunately, there is little statistical evidence on the responsiveness of oil production to price. Drilling has responded strongly to the oil and gas price increases of recent years, but this has not been reflected in increased production.

Present oil price controls

Under present law, the price of domestically produced crude oil is regulated by the FEA in accordance with the "Emergency Petroleum Allocation Act of 1973," as amended. Under these rules, all domestic oil production other than stripper oil (oil produced from properties where the average daily production per well is 10 barrels or less) is subject to price controls. The exact nature of the price controls is determined administratively, but there is a legislatively mandated limit on the average price of the nonstripper oil. Currently, the average price limit is $8.57 per barrel. This is subject to an inflation adjustment which may not exceed 10 percent a year. Price increases in excess of this authority may be recommended by the FEA, but these increases are subject to a veto by either House of Congress within 15 legislative days. Under present law, these controls are mandatory through May 1979, and the President has discretionary authority to continue controls until September 1981.

Under the existing regulations, "old oil" (also known as "first tier oil" or "lower tier oil") is the amount of oil produced on a property up to either 1972 production of all oil or 1975 production of old oil, whichever is less, adjusted for part of the natural decline in production that occurs in any oil field. "New oil" (also known as "second tier oil" or "upper tier oil") is oil produced on a property in excess of this amount. Old oil is controlled at a price averaging about $5.16 per barrel, and new oil is controlled at a price averaging about $10.97 a barrel. (The price of any particular barrel of oil may vary by several dollars from these averages depending on the quality of the oil and its location.) The price of stripper oil averages about $13.28 per barrel. The Administration has announced price increases for old oil up to $5.26 per barrel and for new oil up to $11.75 per barrel by November 1977.

One problem with the crude oil price controls is that they may inhibit investments in enhanced recovery techniques. In many oil fields the natural decline in production resulting from exhaustion of the oil in the field has caused oil production to decline to the point where any additional production resulting from enhanced recovery would be classified as old oil. The price control regulations attempt to deal with this problem by allowing an adjustment for a decline factor, but this adjustment is not adequate in cases where the costs of producing a barrel of oil with expensive, enhanced recovery techniques exceed the controlled price.

Administration proposal on crude oil controls

Under the Administration proposal, the prices of old oil and what is now new oil would continue to be controlled at current price levels, adjusted only for inflation. There would be a higher price for "new new oil," which would be defined as onshore oil discovered after April 20, 1977, in a well that is either more than 2½ miles from an existing onshore well or more than a thousand feet deeper than any well within the 2½-mile radius, as well as oil from an offshore lease entered into after April 20, 1977.

The price of new new oil would be allowed to rise ratably over a 36 month period from the current controlled price for second tier crude oil (about $11 per barrel) to the April 1977 price of imported oil (about $13.50 per barrel), adjusted for inflation. Thereafter, this price would be adjusted upward for inflation.

Under present law these upward price adjustments for new new oil could be implemented through regulations as long as the Administration continues to meet its legislatively imposed average controlled price for all domestically produced nonstripper crude oil, which is currently $8.57 per barrel but which can increase at a rate of 10 percent per year. Otherwise, the Administration could recommend the increased price levels to the Congress, and the increase would take effect if neither House exercised its right to veto the proposal within 15 legislative days.

Under the Administration proposal (as under present law), stripper wells would remain free of price controls. Alaskan oil from existing fields would be treated as new oil at the wellhead, and "new new" Alaskan oil would be entitled to receive the 1977 world price. In the case of Alaskan oil, however, price controls are not the only restraint on the price which may be charged at the wellhead. Current transportation costs for Alaskan oil average about six dollars per barrel, and because the market will not permit the refiner acquisition cost of Alaskan oil to exceed that of imported oil, the actual wellhead price for Alaskan oil will be less than the wellhead price of new oil in the lower 48 States.[1]

Natural gas price controls

Under present law, wellhead prices for natural gas which is sold in interstate commerce are regulated by the Federal Power Commission. Gas which is sold intrastate is not subject to Federal price control.

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[1] Under the Administration proposal, shale oil which is discussed later in this pamphlet, would not be subject to price controls and would receive the current world price as in effect from time to time.

Historically, the price of natural gas sold in interstate commerce was controlled at levels ranging from about 14 cents per thousand cubic feet ("mcf") to 34 cents per mcf, depending on the area of the country where the gas was produced and sold. Thus, all interstate gas was sold at levels substantially below those prices charged for an equivalent amount of energy in the form of oil (even in periods when oil prices were far below current levels). Beginning in 1974, prices for gas which is newly committed to interstate commerce have been standardized on a national basis and have increased substantially, so that gas newly dedicated to interstate commerce is now selling at a rate of approximately $1.45 per mcf. However, much gas is selling at prices below this rate under old contracts which were entered before the recent round of price increases.

The FPC has authority to permit "spot sales" of interstate gas at prices higher than controlled prices during limited periods of emergency. In addition, in The Emergency Natural Gas Act of 1977, Congress authorized the President to permit sales of gas at uncontrolled prices to prevent local natural gas emergencies. This authority expired July 1, 1977, but would be extended by the House bill until April 30, 1979.

Natural gas pricing under House bill

The House bill sets a nationwide price ceiling for "new natural gas". The ceiling will equal the Btu-equivalent to the refiner acquisition cost of non-Alaskan domestically produced oil, exclusive of the crude oil equalization tax. Initially, this will be $1.75 per mcf, but it will rise by about 10 percent per year. New natural gas is defined as gas produced from an onshore well which is either 2½ miles away from or 1,000 feet deeper than a well in existence on April 20, 1977, or which taps a new reservoir, or offshore oil from a lease entered into after April 20, 1977. The House bill also establishes price ceilings for "old" natural gas.

2. *Present law*

The present tax treatment of oil and gas income provides several major incentives: the intangible drilling deduction (described above), percentage depletion for independent producers, and the normal investment credit on production-related equipment.

In addition to treating intangible drilling costs as a tax preference item for purposes of the minimum tax on individuals, the Tax Reform Act of 1976 also provided that for individuals (including partnerships and subchapter S corporations) the amount of any deduction which can be obtained for intangible drilling costs is limited to the amount the taxpayer has at risk with respect to he oil and gas activity. Also, that Act provided that any intangible drilling costs with respect to an oil or gas property would be recaptured upon sale of the property to the extent that those costs exceed the amount which could have been deducted were the costs capitalized and deducted through cost depletion.

Percentage depletion for oil and gas wells was generally eliminated for oil and gas wells by the Tax Reduction Act of 1975. However, percentage depletion was retained for the independent producer[2] for average daily production up to a specified exemption level. The exemption for oil was 2,000 barrels a day in 1975 and is being reduced 200 barrels per day a year for 5 years from 1976 through 1980 when the permanent exemption will be 1,000 barrels a day. For 1977, the percentage is 22 percent and the number of barrels is 1,600 per day. Gas wells are allowed an equivalent exemption, but if the taxpayer elects to exempt natural gas, he must reduce his maximum allowable exemption for oil by the Btu-equivalent of the exempt gas. In addition, the depletion rate for the independent producer will remain at 22 percent through 1980, after which it will be phased down to a permanent level of 15 percent beginning in 1984.

In addition, percentage depletion for oil and gas is limited to 65 percent of taxable income, computed without regard to the depletion deduction.

The 10-percent investment credit also applies to equipment used in oil drilling and production. Equipment generally used which qualifies for the credit includes oil derricks, pipelines, storage tanks, and other lease and well equipment.

3. *House bill*

As noted above, the House bill extends for all future years the minimum tax provision on intangible drilling costs of individuals which is currently applicable only for 1977. Thus, under the House bill intangible drilling costs are included as a preference for purposes of the minimum tax on individuals only to the extent that those costs (in excess of the amount amortizable over 10 years or through cost depletion) exceed the individual's oil and gas production income.

4. *Administration position on the House bill*

The Administration supports the provision of the House bill relating to the minimum tax treatment of intangible drilling costs.

5. *Other Congressional consideration*

a. Action in the 94th Congress

The Finance Committee made no decisions with respect to additional incentives for oil and gas exploration or production.

b. Other committee action

The Senate Energy Committee has reported out the Administration's natural gas pricing proposals without any formal recommendation.

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[2] Under the Tax Reduction Act of 1975, the percentage depletion deduction generally was restricted to independent producers and was eliminated for major oil companies, by denying the deduction to an "integrated" operation, that is to a taxpayer

(1) who sells oil or natural gas or their products through a retail outlet which he or a related person owns, or

(2) who sells oil or natural gas or their products to any person who is contractually obligated to the taxpayer to market or distribute the latter's oil or gas, etc., under the taxpayer's trademark or trade name, etc., or who leases a retail outlet from or is controlled by the taxpayer. The deduction is still available to integrated operations provided that their gross receipts for sales of oil, gas, etc., from all retail outlets do not exceed $5 million annually. (Code section 613A.)

6. Areas for committee consideration

The Administration believes that its plans for increasing some controlled prices provide sufficient incentive to increase U.S. oil and gas production. Others, particularly industry officials, disagree; they contend that additional incentives are necessary.

In determining whether any additional tax incentives are needed, the amount of incentive provided through oil and gas prices could be considered. Most proposals which have been discussed focus on providing new incentives for the discovery of new reservoirs of oil and gas and incentives to increase the percentage of oil that can economically be recovered from existing reservoirs. As a result, most proposals for additional incentives provide credits or additional deductions for exploratory drilling or for enhanced recovery techniques.

1. *Price incentives*

The House bill provides for natural gas price increases up to $1.75 per mcf for new natural gas. By November, the price of new oil will be $11.75 per barrel, and the Administration plans to adjust it upward for inflation. The Administration also plans to develop a category of new new oil which will sell at the current market price, or approximately $13.50. To the extent that these prices in combination with existing tax provisions are seen as inadequate incentives, additional tax incentives could be considered to stimulate additional exploration and production efforts.

2. *Exploratory wells*

Many proposals focus on exploratory wells because they involve the highest risk. Wells other than exploratory wells (so-called developmental wells) are on the average substantially less risky than those classified as exploratory wells by the industry. On the average, over 70 percent of developmental wells are successful, whereas only 25 percent of the exploratory wells succeed. Nonetheless, in some cases a particular development well can also involve considerable risk (for example, where the well is drilled to determine the outer perimeter of a previously tapped reservoir).

With respect to incentives for exploratory wells, the Administration's definition of new new oil is intended to provide these wells with a price set at current market prices. However, it has been argued that the definition proposed by the Administration is somewhat restricted (it includes onshore wells drilled at least 2½ miles from existing wells or 1,000 feet deeper than existing wells and offshore wells in leases entered into after April 20, 1977). Thus, the Committee may want to consider the possibility of tax incentives for exploratory drilling which could be applied to dry holes as well as to successful exploratory wells.

The definition of what should be included in the term exploratory well has caused some difficulty in the past. The most accurate definition would be a well which in fact hits a previously untapped reservoir. It is difficult, however, to apply this definition to any incentive which is also to be given for drilling dry holes. Moreover, even with successful wells, it can be difficult to determine whether or not the oil being produced actually comes from the same reservoir which other wells have already tapped. The alternative approach is to establish a somewhat arbitrary but objective rule similar to that proposed by the

Administration for price control purposes. For example, any well drilled beyond two and one-half miles from any producing well or drilled more than 1,000 feet deeper than any existing well could be treated as an exploratory well. Alternatively, these two approaches to a definition could be combined by providing that any well (and any dry hole) meeting the 2½ mile or 1,000-feet test would automatically be eligible, while other successful wells would be eligible where it could be established that they did in fact tap a new reservoir. This combination approach is adopted for the definition of new natural gas in the House bill.

Since most of the costs of drilling exploratory wells are deducted currently as intangible drilling costs, under present law (as discussed earlier in this pamphlet), any additional incentive would probably take the form of a credit, either as an addition to the existing investment credit or as a new separate credit.

3. *Geological and geophysical costs*

As an alternative to providing new incentives directly for oil and gas exploratory drilling, incentives could be provided for geological and geophysical (G&G) costs. Allowing these to be expensed rather than capitalized would result in a revenue loss of approximately $300 million in the first year, about $200 million in the second year and in the range of $150 to $200 million in subsequent years. These costs generally relate to exploration in new areas. The relevant costs include aerial photography, geological mapping, airborne magnetometer surveys, gravity meter surveys, and seismograph surveys. Since these costs must currently be capitalized in most situations, an incentive could be provided either by allowing a current deduction or by establishing a special credit based on these expenditures. Under present law, G & G costs are part of the basis which is written off through the depletion deduction. Thus, for the major oil companies, who use cost depletion, expensing G & G costs would amount to an acceleration of deductions which they will eventually take over the life of the well. For smaller producers, who are still entitled to percentage depletion, expensing G & G costs would amount to an additional deduction because percentage depletion is not limited to costs incurred.

4. *Enhanced recovery*

The Committee may also want to consider incentives relating to the costs of enhanced recovery techniques. The technology for so-called secondary recovery processes, generally including water injection and gas injection processes, is considered to be well-developed, and the processes (particularly water injection and gas reinjection processes) already are applied routinely to many oilfields. In fact, water injection is often used as a primary recovery technique, and is applied when the well first begins producing oil. However, more sophisticated recovery techniques, often referred to as tertiary recovery processes, are currently used less frequently because of the substantial costs involved. These processes include thermal recovery methods (steamflooding and fireflooding) and the injection of miscible (i.e., mixable materials, such as liquified petroleu mgases which are byproducts of refined petroleum) or detergents or other chemical agents to remove oil clinging to rock formations. Many of these methods involve relatively high costs.

The Administration's price control proposals provide that by administrative action oil produced through tertiary recovery techniques is to receive the current market price of $13.50, rather than the lower controlled prices. The Administration proposes to define oil produced through tertiary recovery by listing a series of specific techniques. The incremental oil produced as a result of the application of these techniques would be deregulated if the FEA determines it would otherwise be uneconomic to apply the techniques. The incremental oil production would be determined by taking the total oil production from each property and subtracting an estimate (made by State agencies) of the amount of oil which would be produced without tertiary recovery.

ERDA has developed a program to reduce the time-lag between beginning enhanced oil recovery techniques and actual oil production. It has undertaken field tests on a shared-cost basis with a private industry to evaluate the technical, economic and environmental feasibility of the most promising enhanced oil recovery methods. For fiscal year 1977, 22 pilot-size tests and one demonstration size test are underway. They include six micellar-polymer, five carbon dioxide, four improved waterflood and seven thermal pilot size tests, and a miscellar-polymer economic pilot demonstration. ERDA also is studying supplies and demands for chemicals used in micellar-polymer and carbon dioxide injection technologies and environmental constraints on steam drive technology. ERDA has budgeted $23.9 million for enhanced oil recovery research in fiscal year 1977 and $46.4 for fiscal year 1978.

5. *Additional incentives*

If additional incentives are desired for any of the above types of expenditures for enhanced recovery, they could take the form of allowing deductions for items currently required to be capitalized or a tax credit for any of the desired types of exepnditures. Under present law, the IRS position (Rev. Rul. 73–469, 1973.2 C.B. 84) is that expenditures for at least certain types of tertiary recovery techniques cannot be deducted currently if additional recoverable reserves are obtained from application of the techniques. Moreover, the IRS view (not expressed in any published position) is that expenditures for secondary recovery, such as water injection wells drilled to boost production of an existing production field, do not constitute intangibles eligible for the current intangible drilling deduction. Thus, the Committee could provide an incentive in this area explicitly allowing these costs as a deduction in the same manner as the current treatment of intangible drilling costs.

B. Oil Shale

1. Background

Oil shales[1] are underground sedimentary layers of finely grained rock which is rich in organic matter. The oil which can be extracted from this shale requires only minimal additional refining in order to make it equivalent to conventional crude petroleum.

Oil shale is a major but undeveloped fossil energy resource in the United States. Total U.S. oil shale resources have been estimated to contain 2,400 billion barrels of oil. Depending on their quality, the oil shale deposits could produce from 10 to 100 gallons of oil per ton, with approximately a quater of the deposits geenrally estimated to contain 25 or more gallons per ton. High grade oil shale deposits containing approximately 600 billion barrels of oil—an amount equal to the known world reserves of oil—are located in Colorado, Utah, and Wyoming. These reserves are more than 10 times greater than U.S. proved petroleum reserves and could supply enough oil for 100 years at current consumption rates.

Total U.S. oil shale resources have been estimated to contain 2,400 billion barrels of oil. Depending on their quality, the oil shale deposits could produce from 10 to 100 gallons of oil per ton, with approximately a quarter of the deposits generally estimated to contain 25 or more gallons per ton.

The Federal Government owns approximately 84 percent of these western oil shale resources. Another 10 percent is privately held and the ownership of the rest is presently contested.[2] Because of the Federal Government's control of this resource, government policy is the critical factor in its development.

The United States also has relatively minor deposits of tar sands from which an oil almost identical to the oil produced from oil shale can be obtained.[3] These sand deposits contain a black, viscous (tar-like) oil which can be extracted by heating. Most United States' tar sands are located in the State of Utah. Although some problems remain in the development of the strip mining technology for tar sands, the process by which the oil is extracted and refined is well established.

Two methods of extracting oil from shale have been tested, both on smaller than commercial scale. The first method involves conventional deep mining or surface ("strip") mining combined with subsequent processing of oil shale on the surface. A variety of surface processing techniques have been tested; all require that the mined shale be crushed, then retorted (heated to 480°C) to release the oil, which closely resembles crude petroleum.[4]

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[1] Shale is a rock that is formed by the consolidation of clay, mud, or silt, has a finely stratified or laminated structure ,an dis composed of minerals essentially unaltered since deposition.

[2] Brazil, Scotland, Eastonia, Russia, Yugoslavia, China, Zaire, South Africa, and Australia also have oil shale deposits, which though smaller than those in the United States, are significant.

[3] The world's most significant tar sand deposits are located in the Western Provinces of Canada. The oil in the Canadian tar sand fields is estimated to exceed at least the total amount of petroleum already extracted from and still contained in conventional oil fields in the United States.

[4] Oil produced from shale is much closer chemically to conveitional crude petroleum than is oil produced by coal liquefaction.

Although the technology for this first approach is relatively certain, it entails some significant problems. This method often requires enormous quantities of water; it might reduce an area's water supply and increase the salinity of the remaining water. Furthermore, the "spent shale," from which oil has been extracted, has been expanded by the retorting (heating) process and takes up approximately 12 percent more space than the area from which it was mined. Thus, all the spent shale could not be put back in the mine. Surface or "strip" mining of oil shale entails many of the same problems as strip mining of coal. Although most of these ecological problems can be alleviated, they substantially increase the cost of mining processes.

The second method is *in situ* retorting, the underground processing of oil shale. This method largely dispenses with mining and surface processing. In *in situ* retorting, approximately one-fifth of an underground cavity is mined out. The remaining shale is blasted with explosives, leaving a cavern of broken oil shale. Then this underground shale is ignited. The fire is controlled by the amount of air pumped into the cavity. The retorted (heated) shale releases oil which is brought to the surface.

Although most government and industry authorities have reservations about the viability of the *in situ* method, some believe it commercially viable. While this method has the advantage of avoiding the ecological surface destruction entailed in mining oil shale, all its effects are not readily predictable. If conducted on a large scale, the *in situ* method would transform a deep, sturdy layer of shale rock, to a weaker, broken layer which might cause shifting and subsidence, thereby, damaging the earth's surface. The effect of the *in situ* method on underground water supplies has not been determined.

Both mining and *in situ* retorting of oil shale raise issues of reclamation, safety, land and wildlife management, waste disposal, and socio-economic problems, such as "boom towns," which must be resolved.

Oil shale production has several positive side effects. Shale oil is a relatively low surfur, "clean", oil. In addition, processing oil shale deposits yields other valuable minerals and by-products from the rock. An oil shale industry would be located in the vast, generally unpopulated area of three states, where adverse effects would not immediately affect the population and might be overcome by reclamation methods such as replanting.

Despite interest in oil shale dating back to The Teapot Dome era, commercial production of oil shale, whether by mining or *in situ* methods, is generally considered to require at least another decade of technological development before adding significantly to the U.S. energy supply. While a few advocates of *in situ* retorting claim that shale oil could be produced commercially at current world oil prices, most experts' most optimistic estimate is that it would require prices in excess of $18 per barrel (1977 dollars) to stimulate commercial production of shale oil. Assuming prices at least $5 per barrel more than the world price, production might reach at most 1.7 million barrels per day in 1985.

In 1974, the Department of Interior leased four tracts to private industry for oil shale development. Development was undertaken on two tracts in Colorado and two tracts in Utah. Some private companies withdrew from the program at the end of 1975, but development was continued by the remaining leaseholders. The Interior Department suspended lease payments and operations on the two Colorado tracts in August, 1976. In August, 1977, the Department approved resumption of the development of the two Colorado tracts. Operations on the Utah tracks also has been supended and still remain tied up in litigation over title disputes.

In coordination with the Department of the Interior, the Navy and private industry, ERDA is attempting to expedite the commercial-scale production of energy from oil shale. Research includes both *in situ* and modified *in situ* technologies. A total of $30.8 million has been budgeted for fiscal year 1977 and $34.8 million for fiscal year 1978 foi oil shale programs. Many other federal agencies are engaged in environmental, socio-economic, health and safety research related to oil shale.

2. *Present law*

Present law provides a 15 percent depletion allowance for oil shale. Under provisions enacted in 1969, the point of application for the depletion allowance was changed from the mined rock to the higher-value oil after retorting (heating), but before hydrogenation, a subsequent process which makes shale oil generally equivalent in quality to conventional crude petroleum. Businesses engaged in oil shale production would be entitled to all applicable business tax incentives, such as the investment credit under the provisions' general rules.

3. *House bill*

No provision.

4. *Administration position on the House bill*

In the National Energy Program, the Administration proposes that shale oil receive the world price. The Administration does not support additional incentives for shale oil production.

5. *Other Congressional consideration*

Action in the 94th Congress

Title XX of the Tax Reform Act of 1976 as reported by the Senate Finance Committee and passed by the full Senate and H.R. 6860, as reported by the Senate Finance Committee, allowed an increased investment credit of 12 percent for shale oil conversion equipment for a ten-year period. An additional one-percentage point of investment credit was allowed if the taxpayer had an employee stock ownership plan. Title XX was dropped in the House-Senate Conference and H.R. 6860 was not acted upon by the full Senate.

6. *Alternative proposals*

Members' proposals

Under S. 419, introduced by Senator Haskell on January 24, 1977, and referred to the present Committee on Energy and Natural Resources, an oil shale technology demonstration program would be established within ERDA to test the commercial, social, and environmental viability of oil shale technologies.

7. Areas for committee consideration

1. *State of the technology.*—The Committee will have to evaluate whether the present technology for producing oil from oil shale is sufficiently developed for business and investment incentives to be appropriate, or whether it would be better to concentrate on programs to improve the technology by expanding research. Although most experts view shale oil as a long-range energy source, which will only begin to be commercially viable in the next decade, some contend that *in situ* processes are sufficiently advanced to be undertaken on a commercial scale relatively soon. Therefore, even if the consensus is that oil shale production cannot begin on a commercial scale until 1985 or 1990, enacting some tax incentives in the present legislation would assist the developers of *in situ* development more than others and it might also spur along the development of mining processes.

2. *Production credit.*—To encourage the development of oil shale, the Committee may want to consider enacting a production credit. The credit could be made available, on a per barrel basis, to taxpayers who begin shale oil production between now and perhaps, 1985, when oil shale production may be commercially viable. Alternatively, to encourage new investment, a cut-off date for the start of construction for facilities whose production would qualify for the credit could be included. The amount of the credit could be calculated with regard to the difference between the projected per barrel cost of producing oil from shale and the current world price of oil. The revenue loss resulting from a $3 tax credit per barrel of liquid hydrocarbons produced from oil shale is not expected to exceed $5 million annually before 1980.[5] Thereafter, for each large-scale commercial plant in full operation (50,000 barrels per day), the revenue loss would be in the range of $50 to $60 million. By the mid 1980's, the revenue loss could reach $300 million annually.

3. *Percentage depletion.*—To encourage the development of shale oil, the Committee may want to consider increasing the percentage depletion rate. It also could extend the definition of "gross income from the property," which is used in determining the base against which percentage depletion is applied, beyond the retort stage to the hyrogenation stage, the point at which shale oil is generally the chemical equivalent of conventional crude petroleum. The Committee may want to consider phasing out an increase in the depletion allowance in accordance with the phaseout provided in oil depletion for independent producers.

4. *Investment credit.*—The Committee may want to expand the definition of property eligible for the investment credit to include structural components of *in situ* retorts which would not otherwise be eligible for the credit. The Committee might also provide an increased credit, perhaps up to 20 percent, for the period between now and 1985 or 1990, when oil shale production is expected to reach commercial scale.

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[5] The $3 per barrel tax credit is based on the "Oil Shale Production Credit," as proposed in the testimony of R. G. Daniel, V. P., Atlantic Richfield Co., September 19, 1977, during the Senate Finance Committee Hearings on H.R. 8444.

5. *Rapid amortization.*—Alternatively, the Committee could provide rapid amortization of the special facilities required for processing and retorting oil shale. It probably would be unnecessary and inappropriate to extend this incentive to facilities used in refining oil shale because the refining of oil shale is essentially similar to that of crude petroleum.

6. *Research.*—The Committee may also want to provide financial assistance for research and development in the production of oil shale. This could be done through subsidies, loans, loan guarantees, or the allocation of funds from any trust fund which the Committee might establish.

C. Gas From Devonian Shale

1. Background

Shales containing gas, which were formed from 400 million to 350 million years ago in the Devonian period of the Paleozoic era, have been located in Ohio, West Virginia, Pennsylvania, New York, Kentucky, Michigan, Indiana, Illinois, Virginia, Tennessee, Mississippi, and Alabama. It is estimated that about 285 trillion cubic feet of producible gas lies beneath Ohio, West Virginia, Pennsylvania, Kentucky, and New York.[1] At the request of ERDA, the U.S. Geological Survey, Department of the Interior, has begun a 5-year study to assess the gas potential of the black shales of the Devonian age which underlie more than 160,000 square miles in the Appalachian basin.

Although some natural gas is being produced on a very small scale from these deposits, commercial exploitation of the Devonian shale resources will not be economically feasible until further research develops better methods for locating the hard-to-detect gas in the tight rock formations and for extracting the gas from the rock.

ERDA is developing an enhanced gas recovery program to study, test and demonstrate unconventional sources of naturally occurring gas including low permeability sandstone reservoirs, Devonian shale, geopressured aquifers and methane from coal seams. ERDA has budgeted $14.9 million for this program for fiscal year 1977 and $27.3 million for fiscal year 1978. The Department of the Interior has budgeted $4.7 million for fiscal year 1977 and $4.2 million for fiscal year 1978 for its part in these programs. Currently analytic studies and field tests are being conducted on Devonian shale in the Appalachian Basin and on the Western gas sands in Utah, Colorado and Texas.

2. Present law

Present law contains no special provisions for gas shale development. However, persons engaged in the business of producing gas from shale would be entitled to all the business tax incentives allowed to business generally under present law.

3. House bill

The provision limiting the treatment of intangible drilling costs as a preference item for all future years for purposes of the minimum tax only to the extent such costs exceed oil and gas production income would apply to drilling activity in gas shales.

A nontax provision of the House bill (sec. 409) authorizes the Federal Power Commission to establish incentive prices for high-cost natural gas. That provision would apply to gas from Devonian shale.

4. Administration position on the House bill

The Administration supports the House bill provision for incentive prices for high-cost natural gas but does not support additional incentives.

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[1] Source: Columbia Gas System Supply Co.

5. Areas for committee consideration

The Committee may want to consider whether it is more appropriate to adopt tax incentives to encourage an activity which is still uneconomic or to treat the production of gas shale primarily as a subject for government-sponsored or -financed research. In the latter case, research on the production of gas from shale might be conducted by the government itself, or subsidized through loans, guarantees, or grants from any trust fund which the Committee might establish.

D. Coal Mining

1. Background

Coal is the most abundant fossil fuel available in the United States. The known reserves are sufficient to meet domestic needs for several centuries. Coal is most important at present because of its suitability as a fuel substitute for oil and gas and because coal has potential use also as a source for synthetic oil and gas. Its drawbacks are the environmental impact and cost of its extraction, transportation and use.

Coal reserves

Domestic coal reserves are approximately 437 billion tons and are found in 30 States. Slightly more than half the reserves are located in Western states and the remainder are in Eastern states. About two-thirds of the total is found in 5 states—Montana, Illinois, Wyoming, West Virginia and Pennsylvania, in order of reserve size.

About 46 percent has a sulfur content below 1 percent, which is below the level deemed satisfactory to avoid air pollution. Almost all of the coal reserves in Montana and 60 percent of those in Wyoming are in this category. Almost the same amount of coal reserves has a high sulfur content and is evenly divided between reserves with a sulfur content of 1 to 3 percent and a sulfur content greater than 3 percent.

Most coal reserves require the higher cost underground mining methods for recovery and the remainder may be recovered by surface mining. Sixty-four percent of the low sulfur content coal and the same portion of the 1 to 3 percent sulfur content coal will require underground mining techniques.

Coal prices and ownership

Coal prices, per million Btu, have been approximately 50 percent of the equivalent oil price and 10 to 20 percent above the equivalent gas price. Coal prices are unregulated and basically responsive to the demand for coal. Electric utilities, the dominant consumers of coal, tend to sign long-term contracts for a mine's total output. The contract price usually reflects the market price at the time when the contract was signed, with provisions for a pass-through of higher operating costs, and occasionally some protection of profit margins.

Generally, domestic coal mines are owned by corporations primarily involved in other economic activities. Of the coal reserves held by the top 150 companies, seventy of the companies are primarily coal producers, but 44 of them produced nothing or less than 100,000 tons in 1976. Oil and gas companies and electric utilities are also major holders of coal reserves. Thirty-nine of the mines produced 2 million or more tons; 8 were owned by coal companies, 9 were owned by companies in oil and gas, and electric utility and steel companies each owned six of the mines. The 9 oil and gas companies held the largest reserves.

Production, consumption and transportation

Domestic production in 1977 is estimated at 665 million tons,[1] about the same as 1976 production. Production has increased by 28 percent since 1968. Electric utilities have long been the major consumer of coal, and during this period, their share of coal consumption increased from 54 to 68 percent. The increased share reflects increased generation of electrical energy and some shifts from use of oil and natural gas as boiler fuel.

Coal production generally is described as being demand limited, that is, the level of production is determined by the demand for it. Consumers of large amounts of coal, primarily electric utilities and some industrial firms, tend to sign contracts directly with mine owners for all or a specific portion of the mine's output. Several years of lead-time are necessary between the decision to open a mine and the start of production. A new surface mine usually can be brought into production in one to three years in contrast with a new underground mine for which four to five years usually are needed before the start of production.

Coal is transported from the mine to the consumer primarily by train. In 1974, railroads carried 66 percent of the coal that moved between mines and consumers. Water transportation and trucks each carried 11 percent of the total. The rest was carried in miscellaneous forms, including a small amount by slurry pipelines.

The interval between the decision to open a new coal mine and shipment of the initial load of consumable coal usually is long enough for manufacture of the additional carriers, including construction of new railroad roadbeds. In the event there is a substantial increase in openings of new mines and increased production from existing mines, all purchasers of transportation equipment may not be able to receive delivery when the equipment is needed.

The existing railroad lines may be extensive enough to carry the coal where it is needed. If they are not and new railroad lines must be put in place, there may be further delay in the delivery of coal by rail to those areas. More flexibility exists with respect to freight cars, because more efficient use of the cars, especially shorter turnaround time, could offset a temporary shortage in the number of cars. Deterioration of roadbeds in some sections in the country is being corrected under a program which was begun in April 1977 under the Railroad Revitalization and Regulatory Reform Act of 1976.

Expansion of mining capacity

The proposed National Energy Program, as presented by the Administration, call for continued, substantial increases in coal consumption by electric utilities—a substantial shift from oil and natural gas to coal, nuclear fuel of other sources. Projections made in 1976 indicate current plans to expand coal production capacity by about 440 million tons by 1985 over 1976 levels. The net gain in current productive capacity will be reduced by about 140 million tons by 1985 as some producing mines are depleted. These expansion plans assume that potential difficulties with the labor force and transportation systems would not seriously restrict deliveries of coal to consumers.

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[1] This estimate, made in August 1977 by the National Coal Association, reflects downward projections from 700 million tons and is based on reduced production because of wildcat strikes and other factors.

Mining research and development

Mining research and development has several objectives: increasing efficiency with more reliable equipment and with new remote control techniques; improving deep mining techniques; increasing recovery; developing surface detection techniques and reducing sulfur content.

Both deep and strip mining involve environmental problems. Associated with underground mining are subsidence of surface land and water contamination. Restoration of the land surface and contours is a major environmental objective for strip mining.

Methane gas is found in coal seams and may be derived from coal. Techniques are being developed by ERDA and the Bureau of Mines to remove methane from coal seams before they are mined. After this gas is recovered, it may be sold to utilities or for industrial use. Recovery of substantial amounts of methane before mining also would diminish a major hazard in deep mining.

The Bureau of Mines has budgeted $57.8 million for fiscal year 1977 and $70 million for fiscal year 1978 for research and development in advanced coal mining technology, including three demonstration projects of longwall mining in New Mexico, Illinois and Kentucky; two demonstrations of high speed mine development with a shaft borer in Alabama and a tunnel borer in West Virginia; three demonstrations of automated roof bolter/miner combinations in West Virginia and Pennsylvania; and demonstrations of recovery of commercial quantities of methane in Alabama, West Virginia and Oklahoma. Programs for underground and surface machinery and for coal handling are also underway.

The Bureau of Mines together with ERDA and the Environmental Protection Agency, plans to spend $2.1 million in fiscal year 1977 and $5 million in fiscal year 1978 on research to reduce sulfur, ash, moisture and other polluting components from coal. (These processes are called coal beneficiation.)

Coal and oil mixtures

Use of coal could be increased by conversion of industrial oil and gas boilers to use of coal and oil mixtures. Technology is currently available to add 30 to 40 percent coal to fuel oil and burn the mixture in boilers not originally designed to burn coal. The cost of converting a gas-fired boiler to coal and oil mixtures would not be substantially greater than converting it to oil, while oil-fired boilers could be converted at a relatively small cost. Full use of this technology could save up to 2 million barrels of oil per day, while 200 million additional tons of coal per year would be burned.

Low-Btu gas as boiler fuel

Technology is available currently for making low-Btu (120–350 Btu per cubic foot) gases from coal for use as substitutes for natural gas (1,000 Btu per cubic foot) as fuels for gas-fired boilers. Such gas-fired boilers must be adapted to accept the new fuel. However, the cost of adapting a boiler to use low-Btu gas is substantially less than the cost of replacing gas-fired boilers with direct coal-fired units. For large industrial facilities, or for smaller units located close to each other, low-Btu gas appears economically competitive with boiler replacement.

Although the gasification technology is commercially available, it has not been used widely. As a result, the economic impacts of meeting environmental requirements and of readjusting gas-fired boilers for the new fuel, and the costs of moving low-Btu gas from the gasifier to the boiler are unclear. Hence, although low-Btu gas generally seems economically attractive, the actual economics will vary according to location. It will probably be most attractive to larger manufacturing facilities or for direct process uses of clean gas flames.

There are two basic types of low-Btu gas. One is a gas of 120–180 Btu per cubic foot, generally suited to small units handling up to a couple hundred tons of coal per day (boilers of 10 megawatts capacity or less). These are the easiest units to build, but the low heating value of the gas limits them to locations very close to the boilers their gas will feed.

The second type is a "medium Btu" gas containing 300–350 Btu per cubic foot. Building units to produce this type of gas is more complex and expensive. On the other hand, medium Btu gas can be shipped up to several miles from the gasifier to the boiler. Also, modifying a boiler for medium Btu gas costs less than adapting a boiler for the low-Btu gas. Medium Btu gas is also usable as a feedstock for chemical manufacture.

In sum, low-Btu gas appears to offer economic advantages over boiler replacement for some large industrial plants or industrial parks. Its conversion cost will be greater than conversion of a gas-fired boiler to oil or to a coal and oil mixture. Most studies assume extraction of this gas from a low-sulfur coal. If environmental constraints require coal cleaning or stack gas scrubbing, the economics would be much less favorable.

Fluidized bed combustion

Fluidized bed combustion technology involves directing an air stream upwards through holes in a perforated, steel-alloy plate in the combustion boiler to raise the coal placed on top of the plate in order to increase the efficiency of industrial boilers.

Fluidized bed processing is a long-standing technology most frequently used in petroleum refining. It has been used infrequently for industrial combustion and probably cannot be made directly applicable to existing boilers of any type. However, if it can be applied successfully on a large scale, it may provide economic and environmental benefits for new, specially-designed coal-fired boilers.

There are two major advantages to fluidized bed combustion boilers. Such boilers can be built smaller, and thus less expensively, than conventional coal-fired units. Also, sulfur oxide emissions can be controlled in the boiler, because sulfur oxide can be absorbed by limestone placed with the coal in the combustion boiler. Thus, the costs of flue gas desulfurization may be avoided.

The major disadvantage of fluidized bed combustion is that its reliability in service and effectiveness of pollution control has not been adequately demonstrated. If ERDA's current program meets its objectives, fluidized bed combustion might be available for industrial-sized boilers in 3 to 5 years and for utility-sized boilers in an additional 5 years.

The costs involved in fluidized bed combustion equipment are unclear, but design simplicity and the smaller size of such equipment may make it more economical than current coal-burning equipment. If, as appears to be the situation in most cases, stack gas scrubbing is not required for fluidized bed combustion boilers, they become attractive economically compared to conventional coal boilers which generally need stack gas scrubbers, provided that the fluidized bed combustion boilers' emission control performance in practice is as good as it appears to be in theory.

2. *Present law*

Percentage depletion

A percentage depletion rate of 10 percent of the taxpayer's gross income from mining, limited to 50 percent of the taxable income from the property, is allowed in the case of coal. Mining includes not only extraction of coal from the ground, but also certain treatment processes [2] to which the coal is subjected by the taxpayer, and transportation of the coal (whether by common carrier or otherwise) from the mine to the plant or mill where the treatment occurs, but not in excess of 50 miles without the approval of the Secretary of the Treasury.

The percentage depletion deduction is allowed even if the cost of the property has been recovered. However, the amount by which the allowable depletion deduction for the taxable year exceeds the adjusted basis of the property at the end of the taxable year (determined without regard to the depletion deduction for that taxable year) is an item of tax preference, and subject to the minimum tax. The determination of whether the allowable depletion deduction exceeds the adjusted basis of the property must be made with respect to each separate property. Thus, if one coal property has an adjusted basis remaining at the end of the taxable year, its basis may not be used to reduce the amount of an item of tax preference resulting from another coal property.

Deductions for exploration expenditures

Under section 617 of the Internal Revenue Code, certain mining exploration expenditures may be deducted currently rather than capitalized and recovered over the life of the mine. Exploration expenses include those paid or incurred during the taxable year to determine the existence, location, extent, or quality of any mineral for which a depletion allowance is permitted, so long as they are paid or incurred before the beginning of the development stage of the mine. For example, expenditures paid or incurred for core or exploratory drilling may qualify as exploration expenditures if they are undertaken to ascertain the existince of commercially marketable coal. However, once a mine with respect to which exploration expenditures were deducted reaches the producing stage, then the taxpayer must recapture the previously deducted expenditures either through including an amount equal to those deductions in income, or through foregoing an equivalent amount of the otherwise allowable depletion deduction. Similar recapture rules apply if the mining property is disposed of, and as to mining property for which the taxpayer later receives a bonus or royalty.

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[2] These processes include cleaning, breaking, sizing, dust allaying, treating to prevent freezing, loading for shipment, and other treatment processes necessary or incidental to any of those processes (sec. 613(c) (2), (4) (A)).

Deductions for development expenditures

Under section 616 of the Internal Revenue Code, development expenditures may be deducted currently rather than capitalized and recovered over the life of the mine. Development expenditures are those paid or incurred during the taxable year for the development of a mine after the existence of coal in commercially marketable quantities has been disclosed. Development expenditures include driving of shafts, tunnels, or galleries, and similar operations undertaken to make the coal more accessible for production. In addition, they may include the cost of core drilling undertaken to delineate the extent and location of existing commercially marketable coal to facilitate its development. If the amount of development expenses exceed the receipts from the mine, the excess may be deferred and deducted in future years. Adjustments to basis must be made for amounts allowed as deductions for deferred development expenses.

Capital gains on royalties

Section 631(c) of the Internal Revenue Code provides that gain realized by the owner of a coal interest on the disposition of that interest may be treated as capital gain, rather than as ordinary income, if the owner retains an economic interest in the coal under any form of contract. Thus, royalty payments may be treated as capital gains on the disposition of a coal interest, even though royalty payments generally are ordinary income. The gain is realized by the owner in the year in which the coal is mined.

For purposes of determining the amount of gain realized, certain expenses which are nondeductible under section 272, e.g., costs of administering the contract, attorney's fees, and charges related to the supervision of the contract, increase the basis of the coal, thereby reducing the amount of gain realized. If the sum of these expenses plus the adjusted basis of the coal disposed of in any year exceed the amount realized as royalties under the contract, the excess is an ordinary loss. Any amount of this excess which does not reduce taxable gain is a deductible loss. In any year in which no gross royalty income is realized under the contract, these expenses may be deductible, without regard to the limitation of section 272, under other sections of the Code.[3]

Other deductible losses

Mine abandonment losses are deductible in the year in which the abandonment occurs.

Coal mine owners and operators also are entitled to the use of the normal tax provisions which are applicable to business generally.[4]

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[3] Where the owner of a coal interest receives capital gains treatment with respect to royalties, or would be eligible for such treatment if royalties were paid during the taxable year, the owner is precluded from claiming the depletion allowance. In such a case, the lessee is entitled to the depletion allowance.

[4] Some coal mine owners and operators also are entitled to use a rapid amortization period for the recovery of the cost of certain coal mine safety equipment required to comply with the Federal Coal Mine Health and Safety Act of 1969, and placed in service before January 1, 1975.

3. House bill

Under H.R. 8444, as passed by the House, tax incentives would be provided to encourage investments in alternate energy property. A taxpayer making expenditures for conversion to fuel sources other than oil, natural gas or their products, may choose one of two alternative incentives—(1) a dollar-for-dollar credit for such costs against the proposed excise tax on business use of oil and gas, up to 100 percent of the taxpayer's use tax liability; or (2) an additional 10-percent investment tax credit, applicable against 100 percent of the taxpayer's income tax liability.

4. Administration position

The Administration supports the House bill and does not support additional incentives.

5. Other Congressional consideration

a. Action in the 94th Congress

In the 94th Congress, the Senate Finance Committee reported both in Title XX of H.R. 10612 (the Tax Reform Act) and in H.R. 6860, a provision which would have allowed an increased investment tax credit for certain types of energy-saving equipment. The provisions reported by the Finance Committee would have increased the investment tax credit to 12 percent for a period of 10 years for equipment to remove pollutants from coal and for a period of 5 years for machinery, equipment and structural components of underground coal mines. Title XX was deleted in conference, however, and H.R. 6860 was not taken up by the Senate before adjournment.

b. Other committee action in the 95th Congress

1. Rail transportation

Section 316 of the Natural Gas and Petroleum Conservation and Coal Utilization Policy Act of 1977, passed by the Senate on September 8, 1977, authorizes the addition of up to $100 million to the Railroad Rehabilitation and Improvement Fund established under the Railroad Revitalization and Regulatory Reform Act of 1976 for the improvement of railroad roadbeds.

2. Strip mining

On August 3, 1977, the President signed into law H.R. 2, the Surface Mining Control and Reclamation Act of 1977, a major revision of the Nation's controls on strip mining and land reclamation.

6. Areas for committee consideration

If the Committee establishes an energy trust fund, it may wish to consider including research and development of new coal mining techniques, the production and use of low- and medium-Btu gas as boiler fuel, and the development of fluidized bed combustion as authorized objects of assistance from such a fund.

E. Coal Slurry Pipelines

1. Background

One way to increase coal supplies is to increase production in areas where coal is not now extensively mined. Coal reserves in Rocky Mountain area coal fields, such as in Montana, Wyoming, and Colorado, are especially important in this regard, because such coal is generally easier to mine than Eastern coal and also because of its low sulfur content. Transportation, however, is always an important factor in coal mining and particularly in obtaining the benefits of increased mining of Western coal.

A slurry pipeline pumps finely ground coal as a mix of coal and water from the mine to a user of the coal or to barges or railroads for further shipment. The technology of slurry pipelines consists of grinding the coal or other material to powder of sufficiently fine consistency to mix well with water, mixing the powder in approximately equal proportions with water, and pumping it through the pipeline. On the longer pipelines, supplemental pumping plants are generally required at various points. At the receiving end, the coal is separated from the water and is dried. It can be burned directly for thermal electric generation or transferred to other transportation modes. Several slurry pipelines are already in operation in the United States, but they carry less than one percent of U.S. coal production.

Plans have been announced by several companies for construction of coal slurry pipelines to transport coal from mine sites to power plants and other consumers. Legislation has been introduced to grant the requisite rights-of-way across Federal lands, and also to establish the power of eminent domain to obtain rights-of-way across private lands. The granting of eminent domain was sought because numerous railroad lines and other private holdings would have to be crossed. Slurry pipelines of significant size would compete with railroads.

A second problem with slurry pipelines involves the significant interbasin transfers of water that would be required to operate such pipelines. One major proposed pipeline would require 15,000 to 20,000 acre-feet of water per year, the equivalent of approximately 4.9 to 6.5 million gallons of water per year. Since most of the proposed pipelines are in arid areas of the West, the large water requirements continue to be the cause of considerable concern. Pipeline legislation introduced in the 94th Congress did not address the issue of water supply.

Coal slurry pipelines have been constructed and operated successfully on a limited scale. The first was a 10-inch pipeline with a capacity of 1.3 million tons of coal per year which ran 108 miles through Ohio from 1957 to 1963, when it was shut down because of reduced railroad freight rates. The second, still in operation, is an 18-inch pipeline with a capacity of 4.8 million tons of coal per year. It runs 273 miles from northeastern Arizona to southern Nevada. In 1973, a 1,030 mile 38-inch pipeline with a capacity of 25 million tons of coal per year was planned. It would run from Gillette, Wyoming, to Pine Bluff, Arkansas.

Large deposits of coal are located within the Upper Missouri River Basin. Previously considered marginal because of their low grade and distance from markets, these deposits now offer good prospects for exploitation because they are easily strippable and are generally considered to be low in sulfur. This is an arid region, however, with relatively limited water supplies. Agricultural and other interests in the region fear that their water supplies will be preempted by coal development. The Yellowstone sub-basin from which the pipeline would originate is the focus of both coal development proposals and concern over the use of limited water supplies. An aqueduct proposal and industrial water marketing contracts to serve coal development have been the subject of considerable controversy, and the contracts are the subject of litigation. A coal slurry pipeline requires less water than on-site processes, such as coal gasification or thermal electric generation. However, by exporting the natural resources in this manner, regional development at the source is reduced considerably.

2. *Present law*

There are no tax provisions in present law specifically related to coal slurry pipelines.

3. *House bill*

The House-passed bill contains no provisions dealing with coal-slurry pipelines.

4. *Administration position on the House bill*

The Administration does not support incentives for coal slurry pipelines.

5. *Other congressional consideration*

a. Action in the 94th Congress

In the 94th Congress, the Senate Finance Committee reported, as part of Title XX of the Tax Reform Act of 1976 and again in H.R. 6860, a provision which would have allowed a 12-percent investment tax credit for coal slurry pipelines for period of 10 years. However, Title XX was deleted in conference and H.R. 6860 was not taken up by the Senate.

b. Other committee action in the 95th Congress

Hearings have been held in the House on H.R. 1609, which would amend the Mineral Leasing Act of 1920 to grant pipelines rights-of-way across Federal lands and, where necessary, would authorize the use of eminent domain to obtain rights-of-way across private lands, contingent upon receipt of a certificate of public convenience and necessity from the Department of the Interior. Further consideration of H.R. 1609 has been postponed until the next session of this Congress. Slurry pipelines would be common carriers and multiple uses of rights-of-way would be permitted.

6. *Areas for committee consideration*

The Committee could provide a tax credit for installing pipeline equipment to carry coal in long-distance slurry pipelines similar to the 12-percent credit provided for 10 years whcih was approved by the Committee in the 94th Congress. The Committee may also want to consider requiring that any adverse economic, environmental and ecological impacts of slurry pipelines be minimized and that persons adversely affected by them be compensated, if the pipeline equipment is to qualify for the tax credit.

F. Coal Gasification and Liquefaction

1. *Background*

While the United States faces the prospect of dwindling supplies of natural gas and oil, as well as marked increases in energy costs, the country possesses abundant deposits of coal. Accordingly, the development and commercialization of processes for converting coal into synthetic gas—coal gasification—or into liquid fuels—coal liquefaction—could represent major contributions to meeting our energy problems.

Gasification

Pulverized coal can be heated at high temperatures with combinations of air, oxygen, hydrogen, or steam to produce combustible gas of low- or intermediate-Btu (heating value) content or, if the product is methanated to increase methane content, high-Btu gas. Coal gasification converts undesirable components in coal, such as sulfur, into chemical forms that can be readily removed from the synthetic fuel gas, and also removes ash.

Low- or intermediate-Btu synthetic gas can be used as fuel in gas turbines or "combined-cycle" plants for electric power generation, as boiler fuel for industrial use, or for certain nonfuel uses (e.g., as gas for chemical feedstock or methanol production). Existing technology for production of low- or intermediate-Btu synthetic gas is well developed and is currently used in many commercial plants outside the United States. High-Btu gas could be used as a replacement for natural gas in industrial, residential, or commercial uses. There are existing technologies, which have been demonstrated commercially abroad, available for converting coal into gas which can then be chemically upgraded to the quality of pipeline natural gas.

In the United States, a few pilot gasification plants are under construction or in operation, but these plants are of smaller size than would be required to produce high-Btu gas for heating residential homes in a city. These test projects, funded in part by ERDA (to be part of the Department of Energy), should determine the most feasible new technology for large-scale production of high-Btu gas. These newer, more efficient technologies being tested may reduce the cost of gas production and may have other attractive features which would warrant accelerated development and scaling the processes up for demonstration or commercial purposes. In addition, some industrial companies in this country, faced with difficulties in acquiring sufficient supplies of natural gas, have contracted for installation of small size, low-Btu gasifiers to produce synthetic gas for their own use, although the cost of producing such synthetic gas is expected to exceed the price of natural gas.

It is estimated that construction of a high-Btu, commercial gasification plant with a capacity of approximately 250 million cubic feet per day probably would take some 5 to 7 years and would cost, in current dollars from $1 to $1.5 billion. In light of the need for further technological advances and the length of plant construction time, it appears unlikely that any large-scale commercial plants will be in operation in this country prior to 1985. There are other technical obstacles facing private enterprises which may be interested in constructing and operating commercial gasification facilities, which include uncertainties about regulatory and pricing policies, the need for large amounts of water in the chemical process and other environmental problems, and limits on available workers and materials.

Liquefaction

Pulverized coal can be converted to synthetic liquid fuel, sometimes called syncrude. Under one existing technology developed in Germany, coal is first gasified to produce a synthetic gas, which is then catalytically converted to liquid products. More efficient "direct liquefaction" processes are in various stages of research and development or demonstration, but there are no commercial-size plants now in operation in this country using a direct liquefaction process.

There are a number of pilot liquefaction facilities in planning stages or in operation designed to improve existing processes or to develop new liquefaction technologies. As funded in part by government programs, research and development of liquefaction technology has a short-term objective of developing to industrial scale the conversion of coal into low-sulfur, low-ash fuel oil suitable for firing electric power generators without air pollution, and a long-term objective of developing to industrial scale the conversion of coal into high grade fuels such as gasoline, methanol, diesel oil, and heating oils.

Using existing technology, it is estimated that synthetic oils from coal might cost as much as $30 per barrel, and that the prices of synthetic and natural fuels may not become competitive for some time. Assuming that competitive technological processes are developed, the remaining constraints to commercialization of liquefaction would appear to be problems of water availability and quality, other environmental and regulatory considerations, and need for workers and materials. Government loans, loan guarantees, or other financial assistance may be required to accelerate commercialization.

2. Present law

The Federal government funds (in many cases, jointly with industry) various research, development, and demonstration projects for purposes primarily of developing newer and more efficient gasification and liquefaction technologies, which can then be commercialized by private enterprise. This effort is directed toward demonstrating new gasification technologies on a near-commercial scale by the early 1980's. Generally, the development of newer liquefaction technologies does not appear to be as advanced.

For fiscal year 1977, the Congress appropriated $77.1 million to ERDA to fund gasification projects and $72.9 million for coal liquefaction projects. The Administration has requested increased funding for fiscal year 1978.

The ERDA authorization bill for fiscal 1978, H.R. 6796, as reported by various House committees, would authorize the following operating expenditures for ERDA programs—high-Btu gasification: $51.2 million; low-Btu gasification: $73.9 million; liquefaction: $109 million. In addition, the bill would authorize the expenditure of $30 million for planning and design of a high-Btu test gasification facility, which would demonstrate and evaluate various promising technologies at a single installation. (The estimated total cost for constructing the facility, including any Federal share of the cost, would be $1.2 billion.) Also, $6 million would be authorized for planning and design of two low-Btu gasification demonstration plants, plus increased amounts for two previously authorized gasification demonstration facilities—a high-Btu, second generation facility and a low-Btu facility.

H.R. 6796 would also give ERDA authority to make loan guarantees for construction, start-up, and related costs of demonstration facilities for converting coal, oil shale, biomass, or other domestic resources into alternative fuels. For example, the bill would authorize loan guarantees for a demonstration gasification plant. However, ERDA would not be authorized to provide funds or financial assistance to commercial-size facilities which industry might want to undertake after testing and demonstration of technologies have been completed.

Both ERDA and the Environmental Protection Agency have instituted studies to identify environmental problems involved in coal conversion processes and to develop pollution control approaches.

3. House bill

Under H.R. 8444 as passed by the House, tax incentives would be provided to encourage investments in coal gasification. A taxpayer making expenditures for coal gasification equipment, related coal handling equipment, or plans and designs for such equipment could choose one of two alternative incentives—(1) a dollar-for-dollar credit for such costs against the proposed excise tax on business use of oil and gas, up to 100 percent of the taxpayer's use tax liability; or (2) an additional 10-percent investment tax credit, applicable against 100 percent of the taxpayer's income tax liability.

Under the House-passed bill, neither the business use credit nor the additional investment tax credit would be available for investments in coal liquefaction equipment.

In order to create an additional incentive for business use of synthetic gas or oil, the proposed business use tax would not apply to gas or oil produced by coal conversion.

4. Administration position

The Administration supports the House bill.

5. Other Congressional consideration

94th Congress

Title XX of H.R. 10612 (the 1976 tax reform bill), as added to the bill by the Senate Finance Committee, would have provided an increased investment credit (12 percent) for the cost of equipment used in either coal gasification or coal liquefaction processes.[1]

All provisions of Title XX were dropped from the tax reform legislation in conference. Subsequently, the Senate Finance Committee reported the Title XX provisions, including the increased investment tax credit for certain energy property, as an amendment to H.R. 6860. However, H.R. 6860 as amended was not taken up on the floor of the Senate and expired with adjournment of the 94th Congress. The Senate Finance Committee replaced the rapid amortization period which was provided in H.R. 6860 for the cost of this equipment with a 12-percent investment tax credit to provide an increased incentive to bring about the desired increase in energy production investments.

6. Areas for Committee consideration

1. *House bill.*—H.R. 8444 provides additional tax credits to stimulate investments in coal gasification facilities (whether pilot, demonstration, or commercial-scale plants), but does not provide any equivalent special tax incentives for investments in coal liquefaction facilities because the House did not believe that the process is developed sufficiently to be affected at this time by the credit. The Committee, however, may wish to extend the gasification incentive provisions to cover investments in coal liquefaction equipment and facilities so that the alternative credits would be available when needed.

The commercial production of both synthetic gas and synthetic liquid fuel, assuming technologies for production at competitive cost can be developed and other obstacles to commercialization are overcome, would represent significant contributions to this country's energy problems. Just as supplies of natural gas are dwindling and eventually will be depleted, and costs for natural gas have increased, so the country's supplies of natural oil will eventually be depleted, and oil prices have risen markedly. Further, the United States depends on imports for a large percentage of its oil supply, resulting in vulnerability to politically motivated supply disruptions. While efficient liquefaction processes generally may not be as advanced technologically in terms of large-scale competitive-cost production in this country, that would not seem a strong reason to deny equivalent incentives to those provided for investments in coal gasification facilities.

2. *Credits for structures.*—If additional tax incentives are thought necessary, the Committee may wish to consider extending eligibility

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[1] The increased credit would have been available for a 10-year period, but this period was reduced to 5 years when title XX of H.R. 10612 was passed by the Senate. The equipment eligible for the credit would have included gasifiers, reactors, and other equipment directly involved in processing the coal; facilities for coal preparation and crushing, removing sulfur or other impurities, preparing and disposing of water used in the process, and product storage; and equipment used to fracture coal in mines and pipe process gas to the surface, as part of underground gasification. However, the credit would not have extended to equipment used in the refining of synthetic crude oil or to the outside structure or shell of a processing plant. While the increased credit was not available for expenditures of funds received as Federal grants, the credit would have been available for expenditures made with funds borrowed from the Federal government or borrowed under a Federal loan guarantee.

for the alternative business use or additional investment tax credits to include categories of structural components necessary for gasification or liquefaction processes but which components would not be required for conventional energy production facilities.

3. Rapid amortization.—Also, a more rapid amortization period could be provided for the recovery of costs incurred in constructing gasification or liquefaction plants. Any such further increases in tax incentives, however, may not be thought necessary in light of the alternative business use or additional investment tax credits already provided in the House-passed bill (if extended to liquefaction investments).

4. Financial assistance, loans, etc.—In light of the huge capital outlays required for construction of commercial-scale gasification or liquefaction facilities, tax incentives alone may not be sufficient to accelerate commercialization once technologies have been developed in pilot or demonstration plants. If new energy tax revenues are to be placed in an energy development trust fund, the Committee may wish to consider including, among the other authorized uses for such trust fund, the providing of financial assistance to gasification or liquefaction projects. Such assistance could take a variety of forms, including loan or price guarantees and construction and leaseback arrangements.

G. Bioconversion

1. Background

Bioconversion is the process of producing energy from various organic substances, called biomass, such as agricultural, industrial, or municipal wastes, or from organic substances (either terrestrial or marine) cultivated especially for use in a bioconversion process. Several conversion technologies exist, including biological, chemical, and thermal processes. The energy produced may be electricity, or gaseous, liquid, or solid fuels, including methane, hydrogen, carbon dioxide, and various heavy, combustible, fuel oils.

Organic materials can be converted into thermal energy by burning, thereby producing either electricity or steam. Biological and thermochemical processes can convert matter into liquid or gaseous fuels, which in turn can be used as a power source. The energy produced by any of these processes can be used as a fossil fuel substitute, and generally is suitable for heating and cooling buildings, running generators, or for industrial manufacturing. Conversion of organic materials into methane yields a product comparable to pipeline natural gas. Similarly, the chemical reduction of organic substances into liquid fuels produces a combustible heavy fuel oil.

Currently, several metropolitan areas use, or plan to use, municipal wastes to produce energy.[1] Some of these areas use the wastes, either alone or in conjunction with conventional fossil fuels, directly as a combustible fuel source for the production of electric, or steam power. Steam also may be used to heat and cool buildings directly. Other metropolitan areas have begun to convert wastes into methane. This is accomplished either by sinking wells into existing landfills and drawing off the gas, or by more conventional "resource recovery" plants which burn the wastes to produce the gas.

An example of a bioconversion resource recovery facility is the recently opened "Americology" plant in Milwaukee, Wisconsin. This plant processes the city's solid waste into reusable ferrous and nonferrous materials, producing six units of energy for every unit that it consumes. The estimated annual minimum production of fiber fuel is 137,500 to 162,500 tons, or approximately 65 percent of the refuse. The balance of the waste is recovered for sale in the form of recyclable aluminum, paper, glass aggregates, and ferrous materials. The fiber fuel is used as a boiler fuel at the Wisconsin Electric Power Co.'s Oak Creek generating station. The fuel is mixed with pulverized coal to generate electricity, and currently represents an energy recovery equivalent of 75,000 tons of coal annually. Eventually, it is estimated that 15 percent of Milwaukee's electrical power will be derived from the reprocessed biomass.

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[1] Areas in which bioconversion waste projects are planned or in operation include: Baltimore, Los Angeles, Milwaukee, Nashville, New York, St. Louis, San Diego, San Francisco, and Seattle.

Agricultural and forestry wastes also are used to generate electricity, methane, and liquid fuels. For example, approximately 40 percent of the electric power needed on the main island of Hawaii now is produced from sugar cane waste. A thermochemical processing facility in Albany, Oregon, initially will use forestry wastes to produce heavy fuel oil. After the wood conversion phase, the plant will test the economic potential for, and the feasibility of, using other biomass products in liquefaction.

In addition to the use of organic waste for the production of energy, several governmental agencies, private organizations, and businesses have begun cultivation of organic substances ("energy farming") for use in bioconversion. NASA and ERDA, for example, are experimenting with various aquatic growths such as kelp (masses of seaweeds) and water hyacinths, as a source of methane. ERDA also is testing the bioconversion potential of terrestrial growths.

One NASA scientist has estimated that the conversion of one acre of water hyacinths could yield between 3,500 and 7,000 cubic feet of methane gas a day. Moreover, it has been estimated that energy farming of land substances could supply approximately 1.8 Quads of energy (the equivalent of 306 million barrels of oil, or 1.8 trillion cubic feet of natural gas) by the year 2000. The combined energy potential of aquatic and terrestrial bioconversion processes has been estimated to be about 6.5 Quads by the year 2020 (the equivalent of 1.1 billion barrels of oil, or 6.5 trillion cubic feet of natural gas). These estimates do not take into account the energy potential available from the conversion of various waste products, such as municipal trash and sludge.[2]

The amount of energy required to produce energy from biomass is very small. Moreover, bioconversion processes may yield valuable byproducts suitable for use in various industrial, commercial, and food production processes. For example, biomass conversion may generate both methane and carbon dioxide. While the methane can be used as a natural gas substitute, the carbon dioxide can be used in refrigeration or in some petrochemical processes. Similarly, terrestrial energy farming enriches the soil of the land used, which generally would not be suitable for other uses. Aquatic forms of biomass production provide marine organisms, such as shellfish, with needed nutrients.

Where municipal and other wastes are converted into energy, disposal problems, particularly pollution, are diminished significantly. This not only alleviates many environmental objections to waste disposal, but also may reduce local taxes since the municipality, in most cases, no longer would have to pay landfill or other disposal related charges. Simultaneously, bioconversion may reduce energy costs to consumers. For instance, it has been estimated that a Nashville, Tennessee project conducted by a nonprofit corporation which generates steampower through the use of a bioconversion waste system will save consumers from 15 to 50 percent of heating and cooling expenses, and that the city will reduce its waste disposal costs by about 95 percent.[3]

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[2] ERDA also has estimated that agricultural and forestry residue could supply approximately 1.2 Quads of energy by the year 2000 (the equivalent of 204 million barrels of oil, or 2.04 trillion cubic feet of natural gas), and approximately 3.5 Quads of energy by the year 2020 (the equivalent of 595 million barrels of oil, or 5.95 trillion cubic feet of natural gas).

A 1971 EPA study estimated that bioconversion of municipal wastes could generate the energy equivalent of 248 million barrels of oil annually by 1980.

Biomass conversion can provide a renewable and economically viable power source alternative for large areas of the United States. To the extent that methane is produced by bioconversion, it can be introduced into the presently existing natural gas pipeline. Although the possibility apparently has not been explored fully, there seems to be no reason why electricity produced by a bioconversion plant could not be introduced into the nation's existing electric utility grid system for distribution to other regions of the country.

Three major problems appear to have inhibited the use of bioconversion. The primary impediment to the full development and utilization of energy from biomass appears to be the enormous capital costs involved. For example, both the growth and processing of biomass requires the construction of new facilities, or the modification of existing plants. To be used as a substitute for conventional fossil fuels in existing or newly designed combustion units, such as utility boilers, or industrial steam and steam-electric boilers, the biomass generally would have to be reduced in size (by milling, pulping, or shredding). The boilers would have to handle both bottom ash and fly ash. All boilers designed to burn coal have ash-handling equipment, and most retrofitted boilers still should have operable ash-handling equipment. Boilers without ash-handling equipment would have to be modified extensively to burn biomass. Particulate emission, such as dust or soot, may be greater when waste-source biomass is fired with coal than when coal is fired alone. High emissions would require that pollution control equipment be increased, thereby increasing plant costs.

Among the technical problems in the firing of waste biomass may be the nonuniformity in the heat content of the fuel due to the presence of water and hard-to-burn materials. This problem can be eliminated in processing the waste, but it requires special facilities. Another problem may be the transportation of materials, or the guaranteed availability of a constant fuel supply. In large metropolitan areas these problems may be overcome easily, but they are persistent difficulties in less populated areas. Another problem is the disposal of the materials that remain after bioconversion. In the case of the production of methane from organic sludge, the residue may amount to 40 percent of the starting material.

The second problem appears to be the fact that biomass traditionally has not been perceived as being a fuel. The third is the overlap of administrative responsibilities for the development and control of processes, such as pollution, related to bioconversion and biomass.

Another problem related to the primary obstacle of capital requirements for a successful bioconversion process is the cost of a facility for the conversion of biomass into methane. Generally such facilities would have to be newly constructed, and designed to produce, collect and purify the gases generated, as well as provide for the recirculation of effluents, and the control of pollution.

In the tax area, the fact that the capital costs involved in the construction of a power facility are recoverable only over the life of the plant, which in the case of a utility is substantial, undoubtedly has inhibited the construction of bioconversion facilities. Similarly, the fact that the investment tax credit does not apply to structural components of a plant probably has induced utilities to acquire qualifying investment credit property rather than channel funds into nonqualifying bioconversion property. Municipalities apparently have been reluctant to issue industrial development bonds for the construction of bioconversion facilities. Not only are the limits on the amount of IDB's too low for the cost of a bioconversion plant, but the Treasury Regulations also provide that where solid waste disposal facilities are involved at least 65 percent of the materials introduced into the facility must be completely valueless.[4] Clearly in the case of biomass the requirements of this regulation could not be met even if the facility was found otherwise to qualify and could be constructed or modified within the limitations of section 103(c)(4)(E).

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[3] Noncombustible items are separated from organic materials prior to the bioconversion process, and generally are sold for recycling.

2. *Present law*

Present law contains several tax incentive provisions which though applicable to biomass conversion projects, contain limitations or restrictions which restrict their value for such projects.

Present law requires that a taxpayer recover capital costs over the useful life of the property, and that all costs which are incurred for the acquisition of property which has a useful life in excess of a year be capitalized. Hence in the case of utility and other power generating property which usually has a very long useful life, taxpayers generally are reluctant to replace the property prior to the completion of its useful life. In addition, since the investment tax credit is available only in the case of nonstructural components, taxpayers are more likely to acquire qualifying property than to invest in nonqualifying property. Accordingly, the investment tax credit may induce capital-intensive firms to utilize their available funds for facilities other than those which could be used to modify an existing plant or to construct a new plant capable of utilizing a bioconversion process.

Section 103(c)(4) provides an exception to the general rule that industrial development bonds are not tax exempt in the case of certain "exempt activities." Among the activities which qualify for the issuance of tax exempt bonds are waste disposal facilities and facilities for the local furnishing of electric or gas energy, if they are available to members of the public upon reasonable demand. However, the Treasury Regulations provide that a waste disposal facility qualifies under this provision only if 65 percent of the materials used in the facility are completely worthless.

Section 103(c)(6) contains an "exempt small issues" exception to the general rule of section 103(c). Under section 103(c)(6) tax exempt financing bonds can be issued for land and depreciable property provided the bond issue is $1 million or less, or in certain cases $5 million or less.

3. *House bill*

No section of the House-passed bill directly addresses the provision of tax incentives for the construction of bioconversion plants or for the modification of existing industrial or utility facilities to accommodate bioconversion processes.

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[4] Treas. Reg. § 1.103–8(f)(2).

The House bill provides tax incentives, outline above, for conversion to boilers using fuel produced by bioconversion processes. Equipment for producing gas by bioconversion is included within these incentives.

4. Administration position on the House bill

The Administration supports the House bill.

5. Other Congressional consideration

Action in the 94th Congress

Title XX of H.R. 10612 (the Tax Reform bill reported by the Senate Finance Committee and passed by the full Senate) and H.R. 6860, as reported by the Senate Finance Committee, would have allowed an increased investment tax credit of 12 percent for equipment or machinery necessary to permit waste (or a combination of waste and other fuels) to be used as a fuel. It also would have allowed the increased investment tax credit for organic fuel conversion equipment. In both instances, the credit also would have been allowed for equipment or machinery necessary for the preparation of the wastes or organic materials for use in a conversion process. The credits would have been allowed for a 5-year period.

Title XX was deleted by the Conference Committee, and H.R. 6860 was not acted on by the full Senate.

6. Areas for committee consideration

1. *Expansion of House bill.*—One action which the Committee could consider to facilitate the utilization of bioconversion processes as alternative energy sources is to clarify the provisions of the Business Energy and Conversion Tax Credit contained in the House-passed bill so as to include the structures and equipment for bioconversion facilities (including any necessary for the preliminary preparation of biomass to make it suitable as an energy source), and the modification of existing utility and industrial plants so that they can use biomass as a fuel. To the extent that new and existing plants use biomass as a fuel source they will be reducing the consumption of fossil fuels.

The Committee also might consider expanding the definition of alternative energy property contained in the House-passed bill to include "equipment for converting an alternate substance into" a synthetic gaseous, liquid, or solid fuel. As approved by the House, the bill is unclear as to whether equipment, for converting an alternate substance into a liquid or solid fuel would qualify as alternate energy property. There does not appear to be any reason why equipment for converting alternate substances into liquid or solid fuel should be excluded from qualifying as alternative energy property. The production of synthetic liquid or solid fuel from an alternate substance, such as biomass, has a potential equal to that of synthetic gaseous fuel for reducing the country's dependence on fossil fuels. Not including such equipment within the definition of alternative energy property could have the effect of discouraging the use and development of equipment for the conversion of alternate substances into solid or liquid fuels. To prevent this result, the Committee should consider making this change in the definition of alternative energy property.

Similarly, the Committee may want to consider expanding the definition of energy property qualifying for the Business Energy and Conversion Tax Credits contained in the House-passed bill to include equipment added to existing commercial or industrial facilities which burn oil or natural gas. or use it as a feedstock, to modify these facilities to use biomass as a fuel or feedstock in replacement of at least 10 percent of the oil or natural gas used before the modification. The House-passed bill would allow the credits where the oil or natural gas replaced was at least 25 percent of the amount used prior to the modification. Reducing the percentage from 25 to 10 percent could result in a significant energy saving in terms of the oil or natural gas no longer consumed by the facility modified. Assuming that each converted facility experiences a normal growth rate which has been anticipated at the time of the modification, the long-range potential use of biomass as an alternate fuel could become even more significant.

The Committee also might consider expanding the definition of property qualifying for both the investment tax credit, and the Business Energy and Conversion Tax Credits contained in the House-passed bill to include those structural components necessary for use in a bioconversion process which are not required in more conventional energy production systems.

2. *Rapid amortization.*—The Committee may want to consider allowing a rapid amortization period for the recovery of costs incurred in the modification of an existing facility to make it suitable for bioconversion uses. Rapid amortization also might be allowed with respect to costs incurred in the construction of facilities necessary for the preparation of biomass for use in a bioconversion process. The latter might include milling, shredding, and compacting equipment necessary for the preparation of biomass for use as a fuel in utility boilers, or industrial steam and steam-electric boilers. Allowing the rapid amortization of these costs would encourage taxpayers to convert or modify existing facilities.

3. *Investment credit.*—To the extent that equipment is used to cultivate aquatic biomass outside the United States, and beyond the Continental Shelf, the Committee may want to modify the investment tax credit to allow it in these cases so long as the biomass is used in a domestic bioconversion plant. This modification in the provisions of the investment tax credit could tend to eliminate a potential disincentive to the use and development of aquatic biomass as an alternative energy source.

4. *Industrial development bonds.*—The Committee also might want to consider clarifying the provisions of section 103(c)(4) of the Internal Revenue Code by specifying that industrial development bonds may be issued for bioconversion plant financing, without regard to the value of the wastes utilized. [Similarly, the Committee could eliminate, in the case of expense incurred for the construction of a bioconversion plant, or the modification of an existing plant to bioconversion capacity, the 50 percent reduction in the Business Energy Tax Credit provided for in the House-passed bill where the facilities or modifications were financed in whole or part by the issuance of indus-

trial development bonds.] These changes in the House-passed bill could encourage governmental units to participate actively in the conversion to alternative fuel sources. Simultaneously it could help raise the capital needed for the construction of new facilities.

5. *Revenue sharing.*—The Committee also might want to consider the possibility of establishing a special revenue sharing formula for use in those cases where local governments establish bioconversion facilities.

H. Oceanic Energy

1. Background

General

The oceans hold the potential for the production of vast amounts of power through the conversion of the energy generated by tides, waves, or thermal and salinity gradients into more readily usable forms of power. While the potentially recoverable oceanic energy is great, many of the technological problems in recovering that energy in an efficient and economically feasible manner have yet to be resolved. At present, both private industry and governmental agencies are engaged in the research and experimentation that are necessary preliminaries to the resolution of these problems. To a large extent these studies are supported by Federal grants, loans, and guarantees, administered by such agencies as ERDA, and the EPA.

Although many oceanic energy sources, such as wave power, and the use of salinity gradients, are in the experimental stages, and thus somewhat far removed from the effective use of tax incentives, other methods of producing energy from the oceans, such as ocean thermal energy or tidal power conversion processes, are closer to the point at which they may become commercially viable alternatives to the use of fossil fuels. To expedite research on, and development of, oceanic power sources, the Committee may want to consider making some of the funds generated from the various taxes contained in the House-passed bill available for grants, loans, or guarantees for the development of these resources.

To the extent that the production of power from oceanic sources is approaching the commercially viable stage, the Committee may want to consider clarifying the House-passed bill to assure that equipment used in an oceanic energy production or conversion process qualifies for the Business Energy and Conversion Tax Credit contained in the House-passed bill.

Ocean thermal energy

Ocean thermal energy is a form of solar power, collected and stored as heat in the warm surface waters of the ocean. Ocean thermal energy conversion (OTEC) is the process of utilizing the temperature differential between warm surface and cold deepsea waters to generate power. Thermal to electric energy conversion and utilization is likely to be most practical where the temperature gradients are large and located close to energy demand. An example of such an area is the Southeastern coast of the United States, where energy generated from the Gulf Stream could be transmitted to the shore for local consumption, or for further transmission by use of the existing electrical power grid system, to other regions on the Eastern seaboard. Tropical and temperate latitudes hold the greatest potential for ocean thermal energy conversion due to the fact that the waters in these areas possess the steepest temperature gradients combined with a seasonally constant ocean temperature.

Generally, proposals for generating power from ocean thermal gradients are based on existing technology, and anticipate the use of either a partially submerged ocean-based platform or hull, or a stationary nearshore power plant platform. The former would be a floating facility, while the latter would be similar in design to existing off-shore oil drilling platforms. Transmission of electrical energy to shore would be byway of a submarine cable. Although shore-based ocean thermal powerplants would be a likely extention of OTEC technology and development, such plants probably would provide only a limited amount of power. The number of locations suitable for the siting of an on-shore OTEC plant would be restricted by the cost of coastal land, local development laws, and the diminished temperature gradients in sea waters as the distance from land is reduced.

Although there are several ways to accomplish thermal to electrical energy conversion, two methods, the "open cycle" and the "closed cycle," are suggested most frequently. In the open cycle method sea water is used as a "working fluid". Warm surface water is flash-evaporated under a partial vacuum, and the resultant water vapor propels a turbine. The vapor then is cooled in a condenser using cold deepsea water pumped up from the ocean depths.

The closed cycle method of conversion, which is preferred currently, uses a working fluid such as ammonia or propane. Warm surface water is pumped through heat exchangers where the secondary working fluid is vaporized; it then expands tremendously, emerging as a very highly pressurized vapor which is used to propel a turbine. Exhaust vapor flows from the turbine to a condenser where it returns to a liquid state as it is cooled by deepsea waters.

Since ocean thermal energy is a form of solar power, it is a renewable energy source. However, it is a low quality heat with a small net conversion efficiency. This means that large amounts of warming and cooling water must be circulated to convert and utilize ocean thermal energy. Nevertheless, the net energy ratio is favorable since no fuel is required for the conversion process, and the potentially recoverable amount of energy is very large.

Electricity produced from the ocean thermal gradients also could be used to electrolyze water to hydrogen and oxygen. The hydrogen then could be piped to shore where it could be burned like natural gas. While some technological advances would have to be made to develop a pipeline which could be used for an extended period without becoming brittle with the flow of the hydrogen, this probably is a minor problem.

Moreover, since the oceans act as a natural photothermal collection and storage medium for solar radiation, solar collectors and storage devices are not required. OTEC systems do require hardware to convert the thermal energy into mechanical energy, and finally into electrical energy.

The technology needed for OTEC systems is relatively low-level technology, that is, no technological breakthroughs are required to implement the system. However, present technology needs to be advanced and refined before an economically viable OTEC system can be deployed. Some of the technical problems confronting the development of ocean thermal technology include: (1) optimization of heat exchangers, both as to cost and performance, as well as the minimization of problems relating to biofouling, corrosion, and materials compatibility; (2) pipeline design for deepsea water intake; (3) perfection of techniques for ocean thermal platform positioning, such as anchoring, mooring, dynamic positioning; (4) biofouling and corrosion of OTEC system components and structures; (5) design of the hull, condenser and evaporator systems; (6) energy transmission and delivery systems; (7) design and testing of system components, especially turbines and pumps. Some of these technological problems are unique to ocean energy conversion systems due to the corrosive nature of the waters from which the energy is extracted.

Aside from the technical problems, there are a number of other potential difficulties which would have to be resolved prior to the implementation of a conversion system. These include possible environmental and legal implications, as well as the potential effect on shipping routes and other laws of the sea.

It has been projected that OTEC plants will be able to produce a wide range of valuable byproducts, including hydrogen, ammonia, and fresh water. Energy-intensive products, such as ammonia, could be shipped from the OTEC plant to on-shore facilities for use in various industrial and agricultural processes.

In addition, it has been suggested that the increased nutrients generated by the artificial upswelling of the deepsea waters would provide the opportunity to cultivate flora, such as kelp, and fauna, such as shellfish. The kelp could be used for its food value, or in a bioconversion process.

Currently there are no commercial OTEC plants in operation, primarily due to the fact that these problems, while under study, have yet to be resolved.

Ocean thermal studies supported by the U.S. solar energy program began in 1972. The OTEC program is now a funded component of ERDA's Solar, Geothermal, and Advanced Energy Systems Office, and will be transferred to the Department of Energy. The objective of this project is to establish the technical and economic feasibility of a complete ocean-based powerplant of at least 100 megawatts, capable of converting ocean thermal energy into electrical power. Present plans are to develop a prototype OTEC plant, with a power output of 10 to 25 megawatts, which can be constructed by 1980. Assuming that the test results are favorable, it is estimated that commercial OTEC plants could be operational, and possibly competitive, by about 1990.

Tidal power

The rise and fall of oceanic tides is largely attributable to the gravitational attraction of the moon. Approximately every 24 hours there are two tidal cycles, that is, two high tides and two low tides. Each daily tidal range differs from every other flow due to the position of the moon relative to the earth's rotation, and due to the position of the sun. As the tides rise and fall energy is produced, energy which is referred to as "tidal power."

The amount of energy generated by oceanic tides depends, in part, upon the extremity of the tidal range. Generally, the mean tidal range must be approximately 18 feet in order for the construction of a tidal power plan to be economically feasible. In addition to a sufficiently high tidal range, a potential tidal power site must include a natural bay of an adequate size, which can be dammed economically, and where the damming will not reduce the tidal range significantly.

Basically there are two preferred methods of utilizing the tides to produce electrical energy: a single pool method, and a two-pool method. Single pool schemes may involve electric generation on either the ebb tide, the flood tide, or both. If generation is in one direction only it is referred to as "single effect" operation. If generation is in both directions of a flow, it is referred to as "double effect" operation. With a two-pool scheme, generation is in one direction only. Pumping in the reverse direction may be a desired supplement for both two-pool and single pool schemes to increase the operating head and power output, particularly under the lowest tide conditions during a month. It is important to note that only a two-pool scheme can provide continuous power and some measure of dependable capacity, without the use of auxiliary generation or energy storage.

Currently France, Russia, and China have modern tidal powerplants in operation. The Rance tidal power project near St. Malo, France generates 240,000 kilowatts, and the Kislaya Guba Bay tidal plant near Murmansk, Russia generates 400 kilowatts. According to a study on tidal power submitted to ERDA,[1] China has numerous tidal power plants either in operation or in the planning stage. South Korea has a 400,000 kilowatt plant scheduled for construction in Inchon Bay, with an estimated completion date of late 1985. Several other plants are under study for possible location in France, Canada, England, and the United States. At present, however, even in locations where construction of tidal power plants is feasible, the cost per kilowatt for energy produced by tidal power is not competitive; and, tidal power is not likely to be competitive for at least another 10 to 15 years.

Preliminary studies indicate that there are only two feasible locations for the siting of tidal power plants in the United States, Cook Inlet, Alaska, and Passamaquoddy Bay, Maine. The reason for this is the need for sufficiently large tide ranges, tidal basins which are big enough to permit a major tidal power development. The mean tide ranges in Passamaquoddy Bay and Cook Inlet are 18.2 feet and 25.1 feet respectively. The total combined developable power in these two regions has been estimated to be limited to about 4,500Mw, with a corresponding annual output of 18.3 billion kwhr. The latter figure is less than one percent of the total electrical power produced in the United States in 1976. To generate this amount of electrical power an international agreement with Canada would have to be executed as to the use of the waters in the Passamaquoddy Bay area.

Projected costs of constructing tidal powerplants range from $2.9 billion for a plant with a 2.1 billion kwhr annual output,[2] to $441 million for a plant with a 590 million kwhr annual output.[3] Over a 50-year period, the total fuel savings of a plant producing 680 kwhr per year would be equivalent to approximately 48 million barrels of oil, or 18 million tons of coal. The total planning and construction phases of a plant are estimated to be in the range of 12 to 13 years; the completed plant should have a useful life of 75 to 100 years.

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[1] Stone & Webster Engineering Corp., 1 Final Report on Tidal Power Study for the United States Energy Research and Development Administration 2–2 (March 1977).

[2] The city of Austin, Texas, with a population of about 252,000, for example, has a 1,000 Mw plant which produces approximately 2.8 billion Kwhr annually.

[3] The city of Lafayette, Louisiana, for instance, with a population of approximately 69,000, has a 180 Mw plant which produces between 500 and 600 kwhr per year.

In addition to the enormous financing required, the prospective construction of a tidal power plant raises a number of environmental issues. Since the construction of a tidal power plant would require the damming of various inlets, and the dredging of the surrounding waters, it could be detrimental to the existing ecological, hydrologic, and oceanographic characteristics of the area. Biological systems could be affected adversely by changes in current mixtures, velocities, and patterns, which, in turn, also could alter sediment distribution, and erosion rates. Construction of the dam, naturally, would restrict movement of marine organisms between the ocean and the newly formed basin.

Some of the technical problems involved in the implementation of a tidal power plant include: (i) design and maintenance of a system whereby the power flow generated by the tides can be equalized over different periods of time through the use of a storage facility; (ii) design of transmission and generating devices capable of withstanding the corrosive effects of the ocean tides and (iii) construction of a damming system.

2. *Present law*

Present law contains no special provisions for ocean energy.

3. *House bill*

The House-passed bill contains no provision which directly addresses the development of OTEC systems. Development and use of such systems would qualify for the business energy tax credit contained in the House-passed bill.

No section of the House-passed bill directly addresses the development and utilization of tidal power. However, the construction of a tidal powerplant would qualify for the business energy tax credit contained in the House-passed bill.

4. *Administration position on the House bill*

The Administration does not support incentives for oceanic energy.

5. *Areas for committee consideration*

1. *Financial assistance v. tax incentives.*—Since the development and use of tidal power appears to be limited to two specific locations within the United States, the Committee might consider providing loans, loan guarantees or other types of financial assistance, perhaps through an energy trust fund, for the construction of tidal power plants rather than attempting to formulate special tax incentives for their development.

2. *Rapid amortization.*—The Committee also might want to consider allowing the rapid amortization of various components used in an operating OTEC plant. This would give taxpayers an incentive to invest in OTEC facilities since they would be able to recover their capital investment over a shorter period of time than otherwise would be the case due to the extended useful lives of most property used in the generation of electrical power.

3. *Investment credit.*—In addition, the Committee may want to provide that the investment tax credit will be allowed in the case of property, so long as the power generated by the facility is transmitted into the United States. Currently the investment tax credit would be allowed if the property was used on the Continental Shelf, but not if the property was used predominently outside the United States. Since OTEC plants might be constructed or used outside the United States, and in some cases not on the Continental Shelf, the credit might not be available. To prevent the disallowance of the credit the Committee could modify the investment tax credit provisions to provide that the credit is to be allowed in the case of property used in an OTEC system.

Due to the unique nature of an OTEC facility, the Committee may want to consider allowing the investment tax credit, and the Business Energy and Conversion Tax Credits contained in the House-passed bill, in the case of structural components used in an off-shore OTEC plant. The investment tax credit could be available for structural components of the plant, depending upon the manner in which the facility was constructed. To eliminate the distinction between permanently moored plants, and those which essentially are floating facilities, the Committee may want to allow the credits in all events, provided that the other usual requirements for the credit are met.

4. *Loan guarantee fund.*—If the Committee decides that OTEC plants are too developmental for the enactment of any of the above provisions, it may want to adopt a provision simlar to the Energy Development Loan Guarantee Fund tentatively approved by the Committee in the 94th Congress in connection with its consideration of H.R. 6860, as approved by the House. The Fund could provide grants, loans, or loan guarantees for the development of OTEC facilities. Grants and loans could be funded, and loan guarantees could be backed, by receipts from the taxes contained in the House-passed bill. Providing loans or guarantees could relieve the substantial difficulty that taxpayers are likely to encounter in seeking the venture capital needed for the construction and operation of an OTEC plant.

I. Chemical Compounds

1. Background

Two related chemical compounds, methanol (wood alcohol) and ethanol (grain alcohol) have been used as gasoline substitutes for automotive fuel in the past when petroleum was scarce. Methanol also can be used in stationary engines in power plants.

Methanol

The United States produces approximately one billion gallons of methanol annually. Although most methanol is currently produced from natural gas, this liquid can also be derived from coal, wood, and urban wastes. Coal, wood and wastes are sufficiently plentiful to make the use of methanol as automotive fuel feasible.

Methanol can be mixed with gasoline in combinations of up to 15 percent methanol to make a fuel which can be used by existing automobiles. Such a mixture of methanol and gasoline may produce more power than gasoline alone and may reduce pollution. However, blends containing more than 15 percent methanol require modifications in some automobile equipment. Using methanol in automobiles presents several problems. First, because methanol is slower to vaporize than gasoline, there may be difficulties starting in a cold engine. Second, a mixture of methanol and gasoline may separate into two layers, especially if water is present. Third, methanol may erode certain materials used in fuel tanks. Fourth, if used generally, the toxicity of methanol might cause environmental damage and thus require preventive measures on equipment.

U.S. coal supplies are ample and the coal conversion technology is sufficiently advanced to make production of methanol from coal practical, although producing a significant amount of methanol from coal would require considerable plant investment. Although there is sufficient U.S. forest land to produce large amounts of methanol from wood. methanol derived from wood would be more expensive than methanol produced from coal. Furthermore, there are competing uses for U.S. wood resources. Although still largely in the research stage, the production of methanol from urban wastes also appears feasible. Some areas, however, may find it more efficient or economical to convert waste for other purposes, for example, to produce steam for electric energy. ERDA is currently studying methanol in its fuels from biomass program and as part of its fossil energy program.

Ethanol

Ethanol used as automotive fuel presently is more expensive than gasoline.[1] Recent petroleum price increases have, of course, narrowed the price gap. Grain prices have also been increasing, although less steeply. The major problem with the current technology for producing ethanol, however, is the amount of grain required. If the United States used its entire grain harvest for ethanol, it would fill only 25 percent of U.S. automotive needs. Thus, even if the cost situation changes to favor ethanol, the supply problem makes large scale use of ethanol difficult at present.

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[1] Alcohol produced from grain would cost at least $1 per gallon, not including distribution costs, sales expenses, and large-scale capital investment.

2. *Present law*

Present law contains no special provisions for the production of methanol or ethanol. Producers of these chemicals would be entitled to claim all appropriate existing deductions and credits, including the depletion allowances for coal and timber, if applicable.

3. *House bill*

No provision.

4. *Administration position*

The Administration supported exempting gasoline mixtures which included alcohol derived from biomass or coal from the 4 cents Federal excise tax on gasoline. The Administration does not support additional incentives in this area.

5. *Other congressional consideration*

a. Action in the 94th Congress

No action by the Senate Finance Committee.

b. Other committee action in the 95th Congress

Food and Agricultural Act.—Earlier this session, Senator Curtis added an amendment to this farm bill to establish a Rural Development Administration which would make U.S. government-guaranteed loans totaling as much as $15 million to construct four pilot plants for producing and marketing industrial hydrocarbons made from agricultural commodities and forest products. Up to $24 million was authorized for research. In his floor statement, Senator Curtis said that one plant should be located in a forestry area, one in a sugar cane area, and two in the grain belt. The conference report on S. 275, as passed by both Houses, includes this provision. The Act now awaits the President's signature.

6. *Areas for committee consideration*

Because the effects of methanol on the environment and on automotive vehicles are not certain and because the known methods for producing ethanol are expensive and require large quantities of grain, the Committee may prefer to emphasize research and development more than incentives for large-scale commercialization.

III. OIL IMPORTS

1. Background

The Trade Expansion Act of 1962,[1] delegates to the President discretionary authority to adjust imports to the extent which he deems necessary so that they will not threaten to impair the national security.[2]

Adjustments to limit imports may take the form of either quantitative restrictions, called quotas, or monetary exactions, usually called tariffs, duties, or import license fees.[3]

Currently, specific import license fees of 21 cents and 63 cents are imposed on each barrel of imported crude petroleum or petroleum products, respectively. Statutory import duties of 5 or 10 cents per barrel, depending on the gravity of the oil, are also imposed. However, these duties reduce the amount of the import license fees.

Under the present crude oil entitlements program for U.S. refiners, the average price paid by domestic refiners for a barrel of crude oil is lower than the world price for oil because the entitlements bought and sold by U.S. refiners results in their cost being an average of all prices paid for crude oil (both domestic and foreign) by all U.S. refiners. The foreign crude oil price used in determining the average price for the present entitlements program does not reflect the cost of the import license fees imposed on foreign crude oil brought into the United States. As a result, U.S. refiners of lower price domestic oil pay refiners of imported crude an entitlement which does not reflect U.S. import fees. Thus, refiners of domestic oil benefit more from the entitlements program than do U.S. refiners of foreign oil because the entitlement program does not require refiners of domestic crude to compensate refiners of foreign crude for the import fees paid by the latter.

The proposed crude oil equalization tax includes the import fees on imported crude in determining the world or market price. Thus, U.S. refiners of domestic crude would lose their current relative advantage vis à vis U.S. refiners of foreign crude.

Some domestic refiners contend that the proposed crude oil tax could put U.S. refiners, who would pay a price equal to the world price plus U.S. import fees for oil, at a disadvantage compared to their current position vis à vis foreign refiners. Some fear that this will result in an increase in foreign refining and more imports of refined petroleum products into the United States with a concomitant decrease in U.S. refining.

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[1] Public Law 87–794 (as amended).

[2] Section 232(b).

[3] In *Federal Energy Administration* v. *Algonquin SNG, Inc.*, 426 U.S. 548 (1976), the Supreme Court upheld as proper under section 232(b) of the Trade Expansion Act of 1962, Presidential action changing from adjustment of oil imports through quotas to adjustment through the imposition of monetary exactions called import license fees.

On an overall basis, the competitive position of U.S. refiners vis à vis foreign refiners depends on all costs, including, for example, transportation, labor, and taxes, and not just one expense item alone. Therefore, any effects of a crude oil tax on imported products is hard to predict, and even more difficult to measure. Moreover, the President might exercise his authority to adjust import fees, duties, and tariffs (or to impose quotas) if he determines that imports, such as refined petroleum products, threaten to impair the national security.

2. *Present law*

In determining whether any imports threaten to impair the national security, the Trade Expansion Act of 1962 specifically requires the President to consider, without excluding other relevant factors:

(1) domestic production needed for projected national defense requirements;

(2) the capacity of domestic industries to meet projected national defense requirements;

(3) existing and anticipated availabilities of the human resources, products, raw materials, and other supplies and services essential to the national defense;

(4) the requirements of growth of industries, supplies and services essential to the national defense, including the investment, exploration, and development necessary to assure such growth; and

(5) the importation of goods in terms of their quantities, availabilities, character, and use as those affect industries essential to the national defense and the capacity of the United States to meet national security requirements.

In administering actions taken under this authority, the President must also recognize the close relation of the U.S. economic welfare to national security, and must consider the impact of foreign competition on the economic welfare of individual domestic industries. In addition, any substantial unemployment, decrease in Government revenues, loss of skills or investment, or other serious effects resulting from the displacement of any domestic products by excessive imports are to be considered, without excluding other factors, in determining whether such weakening of the U.S. internal economy may impair the national security.

3. *House bill*

The House bill contains no provision relating to the treatment of oil imports nor the impact of the crude oil equalization tax on the U.S. refining industry. However, the Ways and Means Committee report on the tax provisions of the bill contains the following statement:

"The Committee understands that the crude oil equalization tax and other taxes in this bill may adversely affect the U.S. oil refining industry, whose existence is essential to national security. The Committee requests that the Administration, using existing authority, take appropriate administrative action if these taxes, together with import license fees and tariffs on crude oil and petroleum products and other costs of U.S. laws and regulations (including the tax treatment of foreign refineries) result in the domestic refining industry's being at a competitive disadvantage in relation to foreign refiners." [4]

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[4] Report No. 95–543, Vol. II: Appendix, 195.

4. *Administration position on the House bill*

The Administration is satisfied with the House bill and with the Ways and Means Committee report.

5. *Other congressional consideration*

Action in the 94th Congress

The Senate Finance Committee considered neither import controls nor the President's authority to adjust imports.

In early 1975, the Congress passed a bill, approved by the Finance Committee, to suspend for 90 days the President's authority to increase import license fees on oil. This followed the imposition of a $1 per barrel license fee by President Ford. The bill was vetoed by President Ford, and the veto was not overridden.

6. *Alternative proposals*

S. 2012, introduced by Senator Haskell and co-sponsored by Senators Bentsen, Gravel and Hansen, would amend section 232 of the Trade Expansion Act of 1962 to require the Secretary of the Treasury to report findings and recommendations to the President within six months of any request, application, or motion to investigate the effects of imports on the national security. If the Secretary finds that the imports of refined petroleum products threaten to impair the national security, the President must exercise his authority under the Trade Expansion Act of 1962, as he deems necessary, including the adjustment of tariffs or fees, to adjust such imports, unless he determines that the imports are not a threat. The bill would require the President to consider the close relation to the U.S. national security of the growth of the U.S. refining industry, its competitive position in relation to foreign refineries, and related economic effects of foreign imports, without excluding other factors, in administering any import adjustments.

7. *Areas for committee consideration*

1. *Presidential authority.*—Some doubt has been expressed as to whether the present language of the Trade Expansion Act of 1962 provides sufficient authority for the President to increase tariffs or fees on imported refined petroleum products. if such imports increase as a result of increases in the price of U.S. products, because of the crude oil equalization tax and other factors. The Trade Expansion Act could be amended to state explicitly that the U.S. refining industry and its growth are essential to the national security and that the President can meet any threat to U.S. refining capacity by adjusting import restrictions. However, the Committee may also want to consider whether an amendment specifically referring to the exercise of the President's authority, with regard to imports of refined petroleum products, may be interpreted as reducing his authority to act with regard to other, unspecified imports. Alternatively, the Committee could adopt committee report language recognizing the domestic refining industry as important to the national security for the purposes of the Trade Expansion Act of 1962. In any consideration of an increase in import tariffs or fees on imported refined petroleum products, the Committee also may want to have the resulting increase in the

prices which U.S. consumers will have to pay for such products evaluated.

2. *Domestic versus foreign refiners.*—There is now a considerable surplus of refining capacity worldwide as a result of the decline in the rate of growth of oil consumption following the rapid price increases of recent years and the worldwide industrial recession. However, in the United States the refining industry is operating at virtually full capacity because of the protection afforded domestic refiners through the differential import license fees on crude oil and refined products, and through the fact that U.S. refiners of imported crude oil receive entitlements while importers of most refined products do not. Costs to consumers would be reduced to some extent if there were no discrimination in favor of U.S. refineries. However, in the absence of either tariff or entitlement discrimination in favor of U.S. refineries, there would be some discrimination against them for at least two reasons. First, costs of U.S. refineries are increased by the Jones Act, which requires that goods shipped from one American port to another must be carried in American ships. Second, foreign refineries owned by U.S. corporations usually pay less tax than U.S. refineries because in many instances corporations have excess foreign tax credits to shelter from tax the income from foreign refineries, and also because in other instances they defer the tax on income from foreign sources by not repatriating the income to the United States. Therefore, some sort of preference for U.S. refineries seems appropriate at the present time. The existing 42-cent differential in the import fees on crude oil and refined products may be large enough to offset these advantages of foreign refineries. If this proves not to be the case, the Committee can address this problem in subsequent legislation.

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